OSBA Statement No. 1
PUBLIC VERSION
6/2/16 HR g TZ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2015-2518438**
UGI UTILITIES, INC. (Gas Division)	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design
EE&C Program

Date Served: April 15, 2016

Date Submitted for the Record: ________________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. <u>Witness Identification and Summary of Conclusions</u>

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries. My consulting practice currently consists primarily of the preparation of analysis and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the filing and interrogatory responses submitted by UGI Utilities Inc. (Gas Division) ("UGI" or "the Company") in this proceeding, to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. OSBA also asked me to review the Company's proposed Energy Efficiency and Conservation ("EE&C") Program.

My evaluation of the Company's filing does not constitute an exhaustive review. If I have not addressed a particular issue, it cannot be inferred that I agree with the Company's proposal for that topic.

I note also that this testimony is being submitted three days after the general due date for intervenor direct testimony. I thank the parties for their indulgence in permitting me this delay. In preparing this testimony, I have not reviewed any of the direct testimony of the other parties.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief overview of UGI's non-residential rate classes, to provide background to the cost allocation, revenue allocation and rate design issues;
- Section 3 reviews my assessment of cost causation and the UGI Gas Cost of Service Allocation Studies ("CSASs");
- Section 4 addresses revenue allocation issues;
- Section 5 addresses rate design issues;
- Section 6 briefly addresses issues related to the Company's proposed EE&C program;

2. <u>Review of UGI's Non-Residential Rate Classes</u>

Q. Before we get into the details of your analysis, please summarize the rate classes under which business customers can take service from UGI.

A. Service to gas consumers falls into three generic categories:

- Sales service, in which customers procure both gas supplies and distribution service from UGI;
- Retail transportation, often called "Choice," service, in which smaller customers purchase gas supply from NGSs and purchase distribution and certain load balancing services from UGI Gas;
- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services from their NGSs

or through unbundled Company tariff charges, and purchase distribution service from UGI Gas.

For cost allocation purposes, UGI Gas aggregates its various rate classes into six rate class groups.

In total, the non-residential rate classes represent about 81 percent of the Company's total throughput, or about 100 million of 122 million Mcf in the test year. Based on my experience, customer size in non-residential classes can vary widely, ranging from small businesses that consume less than 50 Mcf per year to very large industrial customers with individual loads exceeding 2 million Mcf per year.

The following are the non-residential rate class groups specified by UGI for its cost allocation analysis:

Rate N/NT Basic non-residential general service, including Rate N (sales service) and Rate NT (retail Choice service). This class generally consists of smaller customers, but with a wide range of load sizes. The simple average customer size is about six times larger than average residential customer, although there are likely to be many customers that are similar in size to typical residential customers.

Rate DS Delivery service, which is regular (i.e., not retail) transportation service for customers who do not qualify for the larger customer rate classes. The proposed tariff charges include a customer charge and a volumetric distribution charge.

Rate LFD Large firm delivery service, with a minimum daily firm requirement ("DFR") of 50 mcf per day. The proposed tariff includes a customer charge, a "maximum" demand charge and a "maximum" volumetric delivery charge, although it appears that all customers pay the maximum rates.

Rate XD Extended large firm delivery service, which is basic transportation service for large customers with annual throughput of at least 200,000 mcf. The proposed tariff charges include a negotiated customer charge, a negotiated demand charge, and a maximum volumetric distribution charge (which not all customers pay).

Rate IS Interruptible service, limited to customers with alternative fuel capability. UGI Gas is somewhat unusual for Pennsylvania, in that the Interruptible class represents a large share of the total system load (over 40 percent) and includes a large number of customers (322) with a wide range of sizes, with annual throughput ranging from around 100 mcf per year to nearly 600,000 mcf per year, plus one very large customer.[1] Customers are either "manual interruptible," which requires a minimum non-winter consumption of 5,000 mcf, or must be equipped with Automatic Temperature Control ("ATC") which provides for an automatic switch to alternative fuel at a "predetermined temperature setting as determined annually by the company."

Table IEc-1
Review of UGI Gas Rate Classes

	Total	**R/RT**	**N/NT**	**DS**	**LFD**	**XD Firm**	**Inter-ruptible***
Description		Residential Sales/ Choice	Non-Residential Sales/ Choice	Non-Residential Transport	Non-Resid. Transport >50 mcf/day	Non-Resid. Transport >200 mmcf/yr	Non-Resid. Inter-ruptible Transport
Customers	387,919	348,120	38,394	592	464	27	322
Avg. Daily Throughput	335,300	62,313	38,743	8,875	39,903	47,722	137,744
Percent	100%	19%	12%	3%	12%	14%	41%
Percent N/R	100%	–	14%	3%	15%	17%	50%
Annual Mcf/customer	315	65	368	5,472	31,389	645,131	156,138

* Mr. Herbert describes the Interruptible class as consisting of customers in the XD-I, IS and IL classes. The Company's proposed tariff in Exhibit F does not appear to include an XD-I class, and the Company proposes to combine IS and IL into the IS class.

Based on fully forecast future test year; source data from Exhibit D and Exhibit E.

For the purposes of this proceeding, I deem that small businesses primarily take service in the N/NT and DS classes, although there are a significant number of Rate IS customers

[1] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

with relatively low volume levels that would likely take NT or DS service if they took firm service.

3. Cost Allocation

Q. What is the purpose of a utility's CSAS?

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[2] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. A CSAS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from a CSAS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned relatively larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, a CSAS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, a CSAS provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges and commodity charges.

Q. How does a CSAS assign costs to the various rate classes?

A. The underlying principle of a CSAS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable

[2] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. <u>Lloyd v. Pennsylvania Public Utility Commission</u>, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether he should purchase more or less of the utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. The Company submitted two alternative CSAS methodologies in Exhibits D and D1, as well an average of the two CSASs in Exhibit D2. A relatively brief description of the CSAS methodology is presented in the testimony of Mr. Paul Herbert of Gannett Fleming Valuation and Rate Consultants, LLC ("GF") and in Exhibit D. Supporting materials were also provided with the filing in supplemental data requests SDR-COS-1 to 21, as well subsequent responses to a host of interrogatories.

Q. Have you developed your own version of a CSAS?

A. For the reasons detailed below, I have. My version of the CSAS is attached as Exhibit IEc-3.[3] However, also for the reasons detailed below, this analysis is my best effort at this time given limitations on the information available to me, and I expect that the Company will provide additional information in its rebuttal testimony in this proceeding.

3.1 Mains Cost Allocation

Q. What is typically the most contentious cost allocation issue in a gas distribution utility CSAS?

A. Mains cost allocation is generally the most contentious issue, because (a) capital and operating costs associated with gas mains represents a large share of the overall utility revenue requirement, and (b) mains costs cannot easily be assigned to the specific customers who use the mains, in that many mains segments are used by customers in

[3] In preparing Exhibit IEc-3, I first prepared my own version of the Company's filed CSAS shown in Exhibit D, that produced class rates of return that were nearly identical to the Company's version. I then incorporated the modifications discussed in this testimony.

more than one rate class. UGI Gas is no exception to this rule, with mains cost representing some 60 percent of overall claimed rate base.

Q. Please describe the basic issues involved in gas utility mains cost causation.

A. Gas distribution mains are installed to meet two basic objectives: (a) to connect the customer with the interstate pipeline system (or other gas supply sources) and (b) to be able to transport sufficient gas to meet the demand of customers downstream under extreme peak conditions.

Having stated that, however, it is not easy to develop an analytical model capable of reflecting these cost causation factors reasonably. Ideally, the cost of any particular segment of main would only be allocated to those specific customers who are served downstream from that segment. In practice, undertaking such an analysis can be detailed, costly and time consuming. Nevertheless, with the significant improvements in computer modeling of gas distribution systems, one would expect that this approach should become more feasible as time passes.

Q. Has the Company developed such an approach?

A. Yes, it has. Using its Network Analysis software, the Company was able to directly assign the costs for a significant majority of its mains to the specific customers served by those mains. The Company was, for each mains segment, able to identify the specific customers served downstream of that segment, as well as the design day requirements of each customer. Armed with the cost for each segment of main from property records, the Company was then able to allocate the cost of each main customer to each customer served by the main, in proportion to that customer's contribution to design day usage of the main. Costs for each rate class were then derived by summing the costs assigned to each customer within the class.

Q. Do you therefore agree with the Company's method for mains cost allocation in this proceeding?

A. Unfortunately not. The Company's detailed direct assignment method described above was developed for its last base rates case in 1995. In the current proceeding, despite the intervening strides in computer technology and systems modeling software, the Company proposes to take a giant leap backward in cost allocation accuracy, and it has (mostly) reverted to a more traditional mains cost allocation approach.

As a theoretical matter, I would recommend that the Company be required to rely on the mains cost allocation methodology from the last proceeding, upgraded for subsequent technological improvements, modified to reflect changes in customers, demand levels, and rate class definitions. However, traditional mains cost allocation methods, no matter how lacking they may be in either theoretical rigor or in quantitative accuracy, have been used for decades to set gas distribution rates, and they are still in wide use today. I therefore conclude that it is unlikely that the Commission would deem it reasonable to require that the Company to adopt the more detailed and accurate methodology that it used in the last proceeding, when it obviously does not desire to do so.

Thus, I conclude that the parties must rely on a traditional arbitrary allocation scheme for mains in this proceeding.

Q. What are the "more traditional" approaches to mains cost classification?

A. In place of the detailed modeling approaches, various analytical models are used. These methods generally focus on the following questions:

- What causation factors best correlate with mains costs?
- Are mains costs causally related to the number of customers? And, if so, how should the "customer component" of mains costs be derived?
- How should mains costs that are not causally related to number of customers be allocated among the various rate classes?

Regarding the first question, the traditional cost allocation parameters include throughput, peak demand, and number of customers. As a matter of terminology, a throughput allocation factor is equivalent to an "energy" allocator, a "commodity" allocator, and an "average demand" allocator.[4]

Regarding the second question, the common sense argument (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than to connect one large customer. (This common sense argument is supported by some aggregate industry statistical analysis.[5]) As such, mains footage is causally related to the number of customers, and therefore mains costs are partially customer-related. However, some experts disagree, and conclude that no component of mains costs is causally related to customer count.

Relatively recent Commission precedent indicates that the Commission has rejected the use of a customer component for gas distribution utilities in Pennsylvania.[6] However, more recent Commission precedent for electric distribution utilities, where the conceptual

---

[4] Average demand is generally measured as annual throughput divided by 365 days. As such, it is arithmetically equivalent to annual throughput when used as an allocation factor. The ratio of average demand to peak day demand is generally referred to as load factor. High load factor customers typically use gas for manufacturing process applications; low load factor customers often rely on gas primarily for heating purposes.

[5] See, for example, a report prepared by Black & Veatch for Gaz Métropolitain, at http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-B-0005-Demande-Piece-2013_11_15.pdf, pages 12-16.

[6] In a case involving PPL Gas at Docket No. R-00061398, the Commission approved an allocation of all mains costs using a variant on the A&E allocation method advanced by the utility expert witness. In that proceeding, the approved weighting was 40 percent to average demand and 60 percent to excess demand. This weighting was not based on system load factor. PA PUC et al. v. PPL Gas Utilities Corporation, R-00061398, Order Entered February 8, 2007, page 112 – 114. Also,in a case involving the Philadelphia Gas Works ("PGW") at Docket No. R-00061931, PGW proposed to classify some mains costs as customer-related and the balance as demand-related, and proposed to allocate demand-related costs using a peak demand allocator. However, the Commission concluded that no mains costs should be classified as customer-related, and that mains costs should be allocated using a variant of the A&E allocation method advanced by the expert from what was then the Commission's Office of Trial Staff. In the PGW proceeding, the approved weighting was 50 percent to average demand and 50 percent to excess demand. This weighting was also not based on system load factor. See PA PUC v. Philadelphia Gas Works, R-00061931, Recommended Decision, July 24, 2007, page 63, and PA PUC v. Philadelphia Gas Works, R-00061931, Order Entered September 28, 2007, page 80.

arguments regarding cost causation are similar, supports the recognition of a customer component for joint-use distribution plant allocation.[7]

In this proceeding, none of the Company's filed CSASs include a customer component for mains costs.

Q. Have you incorporated a customer component into your mains cost allocation in this proceeding?

A. I have not, for two reasons. First, Commission precedent rejects the use of a customer component for mains cost allocation. Second, I requested the necessary data to conduct the traditional mains cost classification analyses (namely the "minimum system" and "zero-intercept" approaches), but the Company did not provide the necessary historical information.[8]

Q. If there is no customer component of mains costs, what methods are in general use for allocating those costs?

A. The traditional allocation methods include three general approaches, namely a peak demand method, a peak-and-average ("P&A") method, and an average-and-excess ("A&E") method.

Because mains must be sized to meet the design day peak demand of all downstream customers, I conclude that the peak demand method is most consistent with cost causation.

Other analysts, however, favor the P&A method, in which allocation factors represent a weighted average, most often 50/50, of a throughput allocator and a peak demand allocator. Relative to the peak demand method, this approach assigns more cost to

---

[7] For example, PPL Electric has used a minimum system methodology for many years for secondary system plant, and subsequently expanded the minimum system method to primary system plant in its 2010 and 2012 base rates cases. This methodology was fully litigated and explicitly approved by the Commission. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010), and *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2200597, at 113 (Order entered December 28, 2011.)

[8] Despite the request for annual investment information for mains by type and diameter size in OSBA-I-4, the Company was apparently unable to provide the annual investment cost data which is necessary to conduct mains classification analyses using traditional methods.

customers who use gas on a more level basis throughout the year (high load factor customers), and less cost to customers whose gas use is primarily for heating purposes.

The A&E allocation factor is a weighted average of average demand (i.e., throughput) and "excess" demand. Excess demand is measured as the difference between peak demand and average demand. Because this allocation factor consists of an average demand component and a "peak minus average" demand component, it is typically more similar in magnitude to a peak demand allocator than to a P&A allocator. However, this observation depends on the weighting factor used to derive the A&E factor. Under certain specific conditions, namely when the weighting factor is based on the average load factor of all the customer classes, the P&A allocator is identical to the A&E factor.

In Pennsylvania, recent Commission precedent for gas utilities generally supports the use of an A&E allocation method, while for electric utilities, Commission precedent supports the use of a peak demand allocator.

In this proceeding, the Company uses the A&E allocation method. Because the Company uses a weighting factor that is well in excess of the load factor for the classes to whom costs are allocated, the Company's method produces allocation results that fall about half-way between a traditional peak demand method and a traditional 50/50 P&A method.[9]

Q. Are you proposing an alternative to the A&E method for this proceeding?

A. No. While the A&E method as modified by the Company has little or no theoretical appeal, I accept it for this proceeding for reasons of Commission precedent.

Q. Does the Company depart at all from the traditional mains cost allocation approach?

A. Yes, the Company adopts a different approach in three areas:

---

[9] The Company uses a weighting factor with a 42.87 percent component for average demand, based on the Company's calculation of system load factor. However, because the Company does not include the high load factor Rate XD class in this allocation method (as discussed below), the average load factor for the classes to which costs are allocated is much lower. I calculate that the Company's method is equivalent to weighting the peak and average allocators at 77 peak /23 average for large mains and 72 peak/28 average for small mains.

- Mains costs for all Rate XD Firm and one large Rate XD Interruptible customer are directly assigned to their respective rate classes. In effect, the Company maintained some of the direct assignment methodology from its last base rates proceeding, albeit only for the largest customers.[10]

- In Exhibit D, mains costs for interruptible customers (except for the one very large customer) are allocated using an A&E allocation approach in which the "excess" component is deemed to be zero. In Exhibit D1, no mains costs are allocated to these customers.

- Mains costs are split into "small mains" (2 inches or less in diameter) and "large mains" categories, with small mains being allocated only to the R/RT, N/NT, and DS classes, as well as to a small portion of the Rate LFD and Interruptible rate classes.

Q. Is the Company's proposal to directly assign mains costs to large Rate XD customers reasonable?

A. Generally it is. As I indicated, the traditional cost allocation methods cannot accurately reflect the specific assets used to serve specific customers, and do not have a strong theoretical basis for cost allocation. This problem is particularly acute for very large customers, where costs are substantially related to the specific location of the individual customer and its proximity to interstate pipelines. Thus, increasingly, Pennsylvania NGDCs use a direct assignment method for attributing mains costs to large customers.

However, in using a partial direct assignment method, it is important to treat all members of a class consistently. Subjecting part of a rate class to a direct assignment method and part to a generic allocation method can bias the results of the study. A generic method tends to treat all customers in a class as average. However, suppose, for example, a direct assignment method is applied to half the customers in the class that are closest to

[10] Technically, my understanding was that the Company allocated joint-use mains segments in the last case based on peak demand, whereas the Company reports that it uses throughput in its direct assignment method in this proceeding. As any individual mains segment must be sized to meet peak demand, the Company's 1995 method was more consistent with cost causation than the current approach.

transmission pipelines while the other half are subject to the generic allocation method. In effect, the class as a whole is under-assigned costs, because the more expensive customers have been treated as if they were average customers, when in fact they are likely to be above average in expense.

Q. Have you conducted a detailed review of the Company's direct assignment of mains costs to the XD Firm and the one large interruptible customer?

A. No. For this testimony, I rely on the Company's calculations.

Q. What are the cost causation issues related to the allocation of gas distribution mains costs to interruptible customers?

A. By definition, interruptible customers can have their service interrupted during periods of high demand, which generally occur on very cold weather days. Being able to interrupt these customers can provide significant cost savings to the utility, in that the utility can avoid needing to add expensive capacity to meet periods of very high demand. Thus, for components of the distribution system which serve many customers, particularly weather-sensitive customers, interruptible load can provide savings, because the utility need only plan its system to meet the peak demands of the firm service customers. This is particularly true for components of the distribution system that are at or near their physical constraints.

However, interruptible customers provide little or no benefit to those components of the distribution system that serve only a few customers, or which are dedicated to the interruptible customer. The utility obviously cannot interrupt the customer at all times, and therefore at least some components of the distribution system are causally related to serving those customers.

Thus, the value of any particular interruptible customer to the system is heavily dependent on the geography of the system, the location of the customer, the extent to which the interruptible customer relies on mains that also serve substantial firm service loads, and the extent to which the distribution system used by the customer is near its physical constraints during peak periods.

The extent to which a customer is interrupted can be an indicator of whether the customer is providing value to the system.

Q. What has the Company provided with respect to the actual level of interruptions for its Rate IS customers?

A. In its response to OSBA-I-6, the Company indicates that, of the 318 interruptible customers it has had for the past five years, 46 were not interrupted at all over the past five winters, despite some extremely cold conditions. In addition, the Company indicates that its 212 ATC customers have been interrupted automatically at least once over the past five years, but it declined to provide any further detail. Of the remaining 60 interruptible customers, the Company provided a listing of interruptions for the past five years which indicates that the number of interruptions varies substantially, with some customers with only one interruption, but a significant number with more than 10 interruptions, and a few in the 30 to 50 interruptions range. Moreover, the duration of the interruptions also varies substantially, with many being less than a day, but a reasonable number of customers with interruptions extending for 10 days. The large variation in the interruption pattern serves to generally confirm that the value of customer interruptibility is dependent on factors which are specific to the customer and its geographical location on the system.

Q. Earlier in your testimony you indicated that interruptible customers had alternative fuel capability. Does alternative fuel capability have an impact on cost allocation and rate design for interruptible service?

A. Yes. However, it is important to conceptually distinguish between cost causation principles that apply to cost allocation for interruptible customers, and economic competitive conditions that can justify alternative tariff design for customers with alternative fuel capability. From a cost causation standpoint, and hence for the CSAS, the interruptibility of the customer should reflect only the cost savings associated with the utility avoiding the need to construct additional capacity to meet the needs of the customer during extreme peak periods. The only relevance that alternative fuel capability has is that it may ensure that the customer can credibly be interrupted when necessary.

From a revenue allocation/rate design standpoint, customers with legitimate alternative fuel capabilities are often allowed to take service at negotiated "flex" rates. From a revenue allocation perspective, flex rates are a sensible component of the toolbox under certain conditions. In general, if the revenues earned by retaining a customer with flex rates exceed the *incremental* cost of providing service to that customer, other customers will be better off if the discount is offered. However, discounts should only be offered if:

- The resulting rate exceeds the incremental cost of providing service;
- The customer and the utility have made a clear demonstration that the customer has a cost-effective competitive alternative which justifies the specific discount offered; and,
- The discounted rate does not create unfair competitive advantages for some customers at the expense of others.

Therefore, in general, I recommend that the CSAS should reflect cost causation from interruptible customers to the extent practicable. If flex rate discounts below cost-based rates are necessary to meet the competitive cost of fuel for specific customers and they comply with the conditions outlined above, they are better addressed through the revenue allocation and rate design mechanism.

Q. How should the very large interruptible customer be treated for cost allocation and rate design purposes?

A. This customer should be treated as a "flex rate" XD customer, with rates established based on consideration of both cost of service and the price of alternative fuels. In all of the Company's CSASs, mains costs for this customer are directly assigned based on the actual costs for the facilities serving this customer. As such, it is not treated any differently than XD firm service customers. This customer is served by a 20-inch main that was acquired by UGI Gas in 2010 (see Docket No. A-2010-2210236). At least at the time, the main was dedicated to that customer. The interruptibility of this customer likely provides little in the way of distribution benefits to UGI Gas, as the main appears to have been designed to meet this customer's needs. As such, the capital costs for that main should be assigned to that customer, regardless of whether the customer is or is not interruptible. The Company, in fact, recognizes this, as it directly assigns the dedicated mains costs to this customer, even in Exhibit D-1 which excludes allocation of mains costs to all other interruptible customers. Ideally, for cost allocation purposes, this customer would be better included in either a separate rate class or as part of the Rate XD class. However, at this writing, I do not have sufficient information to make this change to the CSAS.

In reviewing the cost information for this customer, however, I note that it appears that the Company has under-assigned depreciation costs. The Company's **confidential** workpapers indicate that the annual depreciation costs for the dedicated mains for this customer were considerably higher for FY 2011 through 2013 than the amount assigned to this class ($9,015) for the forecast future test year in the Company's CSASs. I have corrected this value in my alternative CSAS in Exhibit IEc-3.[11]

Q. *How should the other interruptible customers be treated for cost allocation purposes?*

A. For the reasons I detailed above, the cost to serve each interruptible customer, and the value that interruptibility provides to the utility, are specific to the location and nature of the customer. Absent a detailed evaluation of each individual customer, there is no perfect answer to this question.

Nevertheless, at least some of the interruptible customers have experienced numerous interruptions, and the Company does not include the demands for interruptible customers in its distribution system planning. It would therefore be inappropriate to treat the entire class as firm load. However, it is also true that some interruptible customers have not been interrupted. Moreover, for the reasons detailed above, at least some aspects of the distribution system are likely sized to meet the demands of the interruptible class. It is

[11] In so doing, I reduced general mains depreciation costs for large mains. The Company's response to I&E-RS-61-D indicates that the Company used a composite depreciation factor rather than a direct assignment method for all direct assign customers. The problem that this approach understates actual depreciation costs may also apply to other mains that are directly assigned to Rate XD Firm customers, but I do not have sufficient information to evaluate the impact in this proceeding.

therefore appropriate to allocate some portion of the distribution system to these customers in the CSAS. For that reason, I disagree with the Company's CSAS in Exhibit D-1, because it allocates no mains costs to this group of interruptible customers.

In the absence of a perfect answer, I conclude that the Company's approach in Exhibit D is directionally reasonable. For these customers, the Company uses an A&E allocation factor, in which average demand is based on throughput to these customers, and excess demand is set to zero. In effect, the customers are assigned some mains costs, but less than they would be if treated as firm service.

Q. Turning to a different issue, do you agree with the Company's proposal to allocate "small mains" and "large mains" separately?

A. As a theoretical matter, segregating mains by size or operating pressure may be a useful step toward more accurately matching costs for mains with the specific customers who use those mains. However, the Company's approach does not undertake the necessary analysis to justify this segregation in this proceeding. I therefore recommend that both small and large mains costs, except for those that are directly assigned to XD-Firm and the large interruptible customer, be allocated using the same factors.

Q. Why is the Company's analysis insufficient?

A. At first blush, it would make sense to allocate small mains only to customers who are attached to the system by small mains, and not to assign any small mains costs to the customers who are attached only to larger diameter mains. However, UGI Gas does not even use this simple segregation, in that it assigns small mains costs to all R/RT, N/NT, and DS customers, as well as to a subset of the IS customers. UGI Gas implicitly assumes that all R/RT, N/NT and DS customers are attached to the system as small diameter mains. However, the accuracy of that assumption is not confirmed.[12] While the Company has made an effort to allocate small mains costs to those LFD and IS customers that use them, it appears that the Company has also allocated small mains costs to Rate R/RT, N/NT and DS customers that are served from larger diameter pipe.

---

[12] See OSBA-I-5. In my experience, it is not unusual for many residential and small commercial customers to be attached to the system on larger mains.

More importantly, even if smaller mains are disproportionately used to serve small customers, there is no guarantee that large mains do not disproportionately serve larger customers. In fact, it is likely that there are long extensions of larger mains that serve larger customers, and which provide little or no service to smaller customers. Therefore, when NGDCs segregate mains cost by size or operating pressure in a CSAS, they need to make a reasonable effort to determine whether the larger mains disproportionately serve larger customers. An example of this analysis is Columbia Gas, which develops a more careful assessment of its larger mains in its cost allocation analysis, splitting them into those mains which serve only large customers, those which serve only to attach smaller mains, and those which do both. To my knowledge, UGI Gas has not prepared any kind of similar analysis, and simply assumes that large mains serve all customers proportionately.[13]

As such, the Company's proposal to segregate mains cost by size is, at least as yet, not sufficiently supported. I have therefore modified the CSAS in Exhibit IEc-3 to allocate both small and large mains costs to all customers except those to whom mains costs are directly assigned.

Q. How did the Company develop the class peak demand factors used in deriving the A&E demand factors?

A. Both the OSBA and the OCA requested that the Company provide all of its workpapers used to derive the peak demand levels, but at this writing, only a limited amount of information is available to me regarding the Company's calculations.[14] My analysis is therefore preliminary.

With that caveat, however, it appears that the Company took the design day peak demand forecast for firm load from its 2015 PGC filing, and adjusted it upward for changes in

[13] See, for example, OSBA-I-3.

[14] See OSBA-I-2 and OCA-IV-8.

Rate XD demands.[15] The Company then sets the design day demands for the Rate LFD and Rate XD firm customers based on historical contract demand levels for those customers. The Company goes on to derive a design day demand value for Rate DS customers, using a statistical analysis of daily throughput values, average temperatures, and other variables in the winters of 2013/14 and 2014/2015.[16] Design day demands for Rates R/RT and N/NT are then derived by taking the total firm forecast, deducting the DS, LFD and XD values, and splitting the rest in proportion to average load.

Q. Is this a reasonable approach?

A. No. The design day forecast from the 2015 PGC proceeding is not a reasonable basis for the class-specific design day demands for a CSAS that applies to the forecast test year ending September 2017. All of the throughput and revenue levels for the CSAS reflect the Company's expectations for the substantial changes it expects from conservation effects and customer migration between rate classes. Simple consistency requires that demand allocation factors be similarly adjusted. However, except for Rate XD, the Company's method for developing design day demand allocation factors fails to reflect those changes.

Moreover, in its 2015 PGC filing, the Company determined that it was necessary to ratchet up its calculated design day levels to reflect the fact that actual historical demands on the very cold peak days in the preceding two winters had exceeded statistical estimates. However, with the residual method used by the Company in this proceeding, all of the effect of ratcheting up design day demands is implicitly assigned to the R/RT and N/NT classes.

A particularly significant problem lies with the Rate LFD class, where the Company derives its test year design day demand levels based on the contract demands for 225 customers, but its load and revenue values are based on 464 customers. Despite agreeing

[15] The Company's 2015 PGC filing does not present the details of the calculations for developing design day forecasts. To the extent that information was provided in response to interrogatories in that proceeding, it is no longer available to me. As such, UGI Gas has simply not provided the supporting materials as yet.

[16] The Company also declined to report the details of the statistical analysis, providing only summary results.

that it must construct distribution capacity to meet the contract demand for Rate LFD customers, the Company uses a peak demand value of 54,222 mcf/day in the CSAS, despite the fact that the class contract demand level for the forecast future test year is 73,215 mcf/day.[17] In effect, the Company substantially understates costs associated with the LFD class.

Q. Did you develop an alternative approach for calculating firm design day demand levels?

A. I did, as detailed below.

For the Rate XD class, I reviewed the historical monthly consumption levels for each customer and prepared a simple statistical analysis that derives an estimated design day demand based on design temperature conditions. I then compared those values to both the contract demand levels and the maximum average daily demands in the peak historical month. Based on this analysis, I concluded that the Company's design day peak firm demand for Rate XD was generally reasonable.

For the Rate LFD class, I prepared the same customer-specific statistical analysis as that applied to the Rate XD class. My analysis indicates that many of the Rate LFD contract demands used by the Company are understated, because they are lower than my statistically estimated design day demand values and, in many cases, are actually lower than average daily demands over the course of the peak month. I therefore estimated the design day demand for each LFD customer based on historical statistical relationships. Where that analysis produced a value higher than the reported contract demand, I relied on my calculations. Using this analysis, I estimated the historical class load factor for Rate LFD at 46 percent. I then applied that load factor to the Company's forecast for average daily throughput levels (which reflects customer migration) to estimate forecast test year design day demand. In so doing, I implicitly assume that the new customers migrating into the class will have a load factor that is the same as that for the historical customers. Since the new customers in Rate LFD are generally migrating from Rate DS which has smaller, typically lower load factor customers, my approach should be

[17] See OSBA-I-2(h) and (i).

conservative, in that it likely understates Rate LFD peak demand for the migrating customers.

For the Rate R/RT, N/NT and DS classes, I prepared a simple statistical analysis of monthly load data for the past three years compared to monthly heating degree days ("HDDs"). Using the results, I calculated design day loads for each class based on design HDD conditions, and derived class load factors. For the Rate R/RT and N/NT classes, I applied these load factors to the Company's forecast average day loads for the future test year. For Rate DS, I considered both my simple regression analysis and the Company's regression analysis in developing a load factor estimate.

The peak day demands in my version of the CSAS in Exhibit IEc-3 incorporate all of these calculations.

3.2 Meters

Q. How do gas utilities usually assign meters costs to rate classes?

A. Utilities generally use some version of a direct assignment method. Where plant records are sufficiently detailed, the costs of meters are linked to customers or customer classes, and the costs can simply be assigned to the appropriate class. Other utilities use some variation on a direct assignment method. Typically this takes the form of identifying the number and types of meters that serve the customers within a particular class, either based on actual meters type or replacement meters type. A unit cost value for each type of meter is then derived from either plant records or market conditions, and applied to the number of meters by type for each class. Summing the results by class produces a reasonable allocation factor for meters.

Q. How does UGI Gas assign meters by class?

A. I do not know. Mr. Herbert's testimony indicates only that meters costs are allocated based on the cost of meters and number of customers. When asked to provide detailed workpapers for allocator development, the Company provided a single page of meters total cost value by type of meter by customer class, with no detail as to the number of each type of meter or the cost of that meter, or any information as to how the cost was developed.

Q. Does the Company's method produce a sensible result?

A. Not for small businesses. Table IEc-2 below provides a comparison of indexed per-customer meters costs between UGI Gas in this proceeding, and the UGI affiliates PNG and CPG in their most recent base rates proceedings, as well as recent results for Columbia Gas. The indexes are calculated with the residential class at unity (1.0). Thus, for example, the PNG Rate N/NT index value of 1.4 implies that the cost for the average meter in Rate N is 1.4 times higher than the average meter cost in Rate R/RT. As shown in Table IEc-2, the average meters weighting factor for the small general service class generally ranges from 1.4 to 5.2 for the other utilities, whereas UGI Gas sets it at 16.8.

Table IEc-2
Meters Cost Indices (Residential = 1.0)

	UGI Gas	PNG	CPG	Columbia
System	2.7	1.1	2.6	1.3
R/RT	1.0	1.0	1.0	1.0
N/NT	16.8	1.4	5.2	3.2
DS	30.1	14.7	178.8	26.6
LFD	43.5	30.9	178.8	118.3
XD	63.8	62.1	488.6	159.4
Interruptible	16.7			

Includes accounts 381-385

The Columbia Gas rate classes do not match up perfectly with the UGI classes, but the comparable classes for R/RT, N/NT and XD are reasonably similar in average customer throughput. Columbia's SDS and LDS classes generally have larger average customers than DS and LFD.

Source: Exhibit IEc-3

Q. What appears to be causing this anomalous result?

A. There are many factors which could cause it. Unfortunately, the Company's workpapers do not provide much insight, but there are a few possibilities. First, the workpapers indicate that the values are based on year-ending September 30, 2015. As such, they do not appear to have been modified to reflect customer migration. As was the case for the design day demand allocators, this is simply wrong. Second, the values in Table IEc-2 suggest that the cost for residential meters are relatively inexpensive at UGI Gas compared to the other utilities, which would imply that *all* the non-residential meters cost indices should be on the high side. Third, the Company's response to OSBA-I-8(d) indicates that the Company allocated at least some meters costs among the non-residential customer group based on customer count rather than actual cost of meters. This may cause the non-credible result that although UGI Gas's interruptible customers are generally far larger than Rate N/NT customers, the average meters cost per customer is the same.

I therefore recommend that the Company develop a meters cost allocation factor that reasonably reflects the actual meters cost differences between the classes.

Q. Have you developed an alternative allocation method for meters costs?

A. I have, but it is at best an estimate based on the relationships observed at other Pennsylvania NGDCs. I would hope that the Company will undertake a thorough review of its analysis for its rebuttal testimony, including an assessment as to whether the residential class meters cost is correct, whether customer migration is correctly reflected in the analysis, and whether meters costs can be more accurately allocated or assigned among the non-residential rate classes.

For this testimony, I modified the allocation of meters cost with no changes to the residential class, adjusting the indexed meters cost for N/NT to be 8 times the residential cost (the highest value for any of the other NGDCs), and to allocate the reduction in costs for Rate N/NT to the DS, LFD, XD and IS classes partly in proportion to volume and partly number of customers. This produces a set of indexes for the non-residential customer classes that are all between 2 and 3 times as large as the average for the other NGDCs in my sample.[18] This allocation method is factored into the CSAS analysis shown in Exhibit IEc-3.

[18] The fact that the indexed per-customer costs for all non-residential customer classes must be so much higher at UGI Gas than for all of these other NGDCs suggests that UGI Gas may be understating the residential meters costs.

3.3 Services

Q. How important to the CSAS is the allocation of costs associated with service lines?

A. Service line costs generally represent a large share of NGDC ratebase costs, and UGI Gas is no exception. For the forecast test year, the Company reports that services plant represents some 39 percent of distribution plant and 47 percent of its rate base. Unfortunately, many NGDCs have only limited data regarding the relative cost of service lines among the rate classes.

Q. How does UGI Gas allocate service line costs?

A. It is not clear at this writing. Mr. Herbert states, "Costs related to service lines in Account 380 were allocated to classes, after a direct assignment to each of the XD customers, based on the cost of service lines by size and the number of customers in each class." When asked to provide supporting calculations in OSBA-I-10, the Company provided a spreadsheet showing "allocated footage" for each size service diameter (ranging from 0.25 inches to 8 inches), and cost allocated to each class. No information was provided showing how the footage was allocated, nor how that relates to size and number of customers. The only assumptions that could be gleaned from this workpaper is that the Company used the same cost per foot of pipe for any particular diameter, and that, in general, larger sized pipe diameters have a modestly higher cost per foot. It also appears that the Company has assumed that the services cost per customer are the same for all customers in Rates DS, LFD and Interruptible.

Q. Does the Company's approach produce unreasonable results for small business customers compared to other NGDCs?

A. No. I compared the indexed cost per customer from the UGI Gas analysis with the other utilities I used for the meters cost comparison. The results are shown in Table IEc-3 below. As shown, the indexed cost for both N/NT and DS customers is well within the range of the other NGDCs. I have therefore relied on the Company's allocation method in this testimony.

Table IEc-3 Services Cost Indices (Residential = 1.0)				
	UGI Gas	PNG	CPG	Columbia
System	1.0	1.1	1.0	1.0
R/RT	1.0	1.0	1.0	1.0
N/NT	1.3	1.4	1.3	0.9
DS	5.4	9.7	3.0	6.6
LFD	5.4	20.4	3.0	2.1
XD	11.0	41.0	5.0	1.6
Interruptible	5.4			

The Columbia Gas rate classes do not match up perfectly with the UGI classes, but the comparable classes for R/RT, N/NT and XD are reasonably similar in average customer throughput. Columbia's SDS and LDS classes generally have larger average customers than DS and LFD.

Source: Exhibit IEc-3.

3.4 Gas Supply Working Capital

Q. What base rates costs does UGI Gas incur related to working capital for its gas supply function?

A. UGI Gas's revenue requirement includes the costs associated with $21.7 million in gas storage working capital inventory. The Company also splits its cash working capital claim into that related to distribution and that related to gas supply, with the latter being $8.0 million. Thus, in total, the Company includes some $29.7 million in rate base or roughly $3.7 million in annual costs.

Q. Do you have a concern regarding the allocation of these costs?

A. I do. The Company appears to have an inconsistency between its cost allocation method and its derivation of the gas procurement charge ("GPC").

In the CSAS, the Company allocates these costs between the Rate R/RT and the Rate N/NT on the basis of annual sales volumes. This methodology implies that these costs are related only to providing gas sales service, and are not related to either retail Choice or transportation service.

However, in order to level the better playing field for competition, the Commission requires that NGDCs establish a GPC for recovery of base rates costs that it incurs on behalf gas supply customers. The GPC applies only to non-shopping "sales" customers, is included in the price-to-compare ("PTC"), and is bypassed by shopping customers. The Commission's regulations indicate that the GPC should include the following elements:

> *Natural gas supply service, acquisition and management costs, including natural gas supply bidding, contracting, hedging, credit, risk management costs and* ***working capital.***
>
> *Administrative, legal, regulatory and general expenses related to those natural gas procurement activities, excluding those related to the administration of firm storage and transportation capacity.*[19] (emphasis added)

Thus, the Commission's regulations specifically contemplate including gas supply related working capital costs. If the Company's cost allocation method is correct and these working capital costs are related only to sales service, these costs should be reflected in the Company's calculated GPC. However, as the Company has not included any provision for working capital costs in the GPC, the Company's treatment of these costs is necessarily inconsistent between its CSAS and its GPC.

Q. From a cost causation standpoint, how should these costs be treated?

A. Regarding the gas storage inventory costs, the gas inventories are clearly used to serve sales customers, as the Company purchases gas on a year-round basis and transports it to its market area, using storage to reduce transmission costs. The Company generally does not provide this particular form of load balancing to retail Choice or transportation customers. But in response to OSBA-I-20, the Company argues that it provides summer index pricing and delivery flexibility to Choice suppliers, which it deems to be equivalent to the cost of storage. However, the Company offers no calculations showing this equivalency.

Regarding the cash working capital, these costs are generally related to the lag between the time when the Company incurs the cost of the gas and the time when it receives

[19] 52 Pa. Code § 62.223

payment for the gas (exclusive of time in storage). There are three different possibilities. First, for sales customers, the Company incurs the cost of gas at purchase and the revenues with payment. Second, for Choice customers whose NGSs use the Purchase of Receivables ("PoR") program, the lag is the time between the time when the Company purchases the receivable and when it receives payment. And third, for Choice customers whose NGSs do not use the PoR program, the Company incurs no cash working capital costs. Unfortunately, the Company has not provided any calculations showing the difference in payment lags between sales and Choice customers in the PoR. However, the Company does indicate that 17 percent of Residential Choice and 81 percent of Rate NT Choice is not subject to the PoR program.

Q. How have you incorporated these factors into your analysis?

A. In the absence of any Company analysis regarding storage equivalency, I have assumed that 50 percent of the gas in storage is related only to sales volumes, and 50 percent is related to sales plus Choice volumes. I have included the annual costs associated with sales volumes in a recalculated GPC (included in Exhibit IEc-3).

For the cash working capital costs, I developed a volumetric allocation factor based on sales volumes plus a portion of Choice volumes. For Rate R/RT, I included 83 percent of Choice volumes (100% - 17%) and for Rate N/NT I included 19 percent of Choice volumes (100% - 81%). I also included the portion of these costs related to sales volumes in my recalculation of the GPC.

4. <u>Revenue Allocation</u>

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[20]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the CSAS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

Q. What does your CSAS imply for revenue allocation?

A. Subject to all of the caveats regarding my CSAS analysis that I listed in the previous section, Table IEc-4 below shows the class rates of return at current rates, as well as the dollar cross-subsidy if an across-the-board rate increase were imposed. As shown, the interruptible class has a negative rate of return, even with the modifications to the demand allocation factor described in the previous section. In addition, the Residential class is being heavily subsidized. Because the Residential class represents a large share of distribution costs, the dollar value of the cross-subsidy is relatively large. On a percentage basis, however, the subsidy to the IS customers is larger. Conversely, the

[20] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Note that the criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

N/NT, DS, LFD and XD classes all provide significant cross-subsidies to the R/RT and IS classes.

Table IEc-4 Implications of IEc CSAS for Revenue Allocation		
	Rate of Return Present Rates	**Cross-Subsidy* ($mm)**
R/RT	1.2%	$35.1
N/NT	9.9%	($20.3)
DS	9.8%	($ 3.8)
LFD	9.0%	($ 7.9)
XD	43.8%	($11.0)
IS	-2.8%	$ 8.0
System	4.4%	–

*A positive cross-subsidy value indicates the class is being subsidized; a negative value indicates it is providing the subsidy.
Source: Exhibit IEc-3

Q. What do you recommend for revenue allocation in this proceeding, based on the information currently available to you?

A. I recommend that revenue be allocated with the objective of reducing cross-subsidies, subject to the value of service and rate gradualism principles. For rate gradualism, I adopt a simple rule of thumb that no class be assigned a rate increase that is more than 1.5 times the system average. While there is no particular theoretical basis for this restriction, it is consistent with revenue allocation policies that I have observed in my experience working in Pennsylvania, and it is the limit used by the Company in this proceeding.[21]

The most problematic class is Rate IS group. The Company's proposed treatment for this class appears to vary between witnesses. Mr. Szykman argues that revenues for this class should be based on value of service principles, in which revenues at both current and proposed rates are set based on competitive market conditions. Mr. Lahoff, however,

[21] UGI Gas Statement No. 6, page 21.

indicates that revenues for this class are based "as a proxy" on the average of the two cost allocation methodologies employed by the Company in this proceeding.

For this class, I recommend that the large customer be treated differently from the other customers. Based on my review of the confidential information, I believe that the negotiated rate for this customer would be sufficient to recover the allocated cost for this customer, if it were separately evaluated in the CSAS. For that reason, I propose no change to those revenues.

For the balance of the interruptible class, however, if the reported $4.9 million in current rate revenues used in the Company's CSAS is accurate, my CSAS indicates that a large rate increase is warranted by allocated cost.[22] However, as I noted earlier, interruptible rates are negotiated, ostensibly based on the cost of competing fuels. With current fuel oil prices at relatively low levels, the Company may indeed face the potential loss of customers if a significant rate increase is imposed.[23] Unfortunately, however, the Company has not provided sufficient evidence that the current negotiated rates are necessary to retain these customers.[24] Unless and until such a demonstration is made, I recommend that a 1.5 times system average increase be assigned to these customers. For the reasons I discussed earlier in this testimony, to justify flex rate discounts, the Company must demonstrate for each interruptible customer that:

---

[22] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[23] Mr. Lahoff cites to a decline in the NYMEX crude oil price to below $40 per barrel (UGI Gas Statement No. 6 page 25). The current futures market prices reflect an expectation for modest price increases for West Texas Intermediate crude over the next two years, rising to the mid-$40s by late 2016 and the high-$40s by late 2017. http://www.barchart.com/commodityfutures/Crude_Oil_WTI_Futures/CL consulted April 13, 2016.

[24] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

- The customer has ready access to a specific alternative fuel;
- The flex distribution rate is set approximately equal to the cost of the alternative fuel less the commodity cost of natural gas;
- The flex distribution rate is updated regularly to reflect changes in alternative fuel prices;
- The flex distribution rate revenues used in this proceeding for these customers reasonably reflects current expectations for alternative fuel prices in the forecast test year.

Turning to the Rate R/RT class, the rate increase necessary to bring this class' revenues into line with allocated costs would exceed 1.5 times the system average.[25] I therefore propose that this class also be assigned a 1.5 times system average increase. This increase is reasonably similar to that proposed by the Company in this proceeding for this class.

The largest customers in the Rate XD class are also subject to negotiated rates, but these rates produce revenues well in excess of cost. There is therefore no reason to assign any of the rate increase to this class. However, because these are negotiated rates that are acceptable to these customers, there is also no reason to assign a rate decrease to this class. (In my experience, the Commission is reluctant to assign rate decreases to individual rate classes except in extraordinary circumstances, particularly when the utility is seeking a large overall rate increase as in the current proceeding.)

For the remaining rate classes, N/NT, DS and LFD, the best that can be accomplished is to reduce the cross-subsidies that these classes provide. I therefore calculated revenue allocation values for these classes that reduces the cross-subsidies from these classes by a proportionate amount.

[25] This statement is true under both the Company's cost allocation methods and my own.

The results of this recommendation are summarized in Table IEc-5 below, and presented in detail in Exhibit IEc-3.

Table IEc-5 RDK Proposed Revenue Allocation $mm					
	Proposed Revenue Increase	Percent Increase	Current Cross-Subsidy*	Proposed Cross-Subsidy*	Reduction in Cross-Subsidy
R/RT	$44.18	40.7%	$35.1	$20.5	41%
N/NT	$ 7.27	13.2%	($20.3)	($12.6)	38%
DS	$ 1.43	13.5%	($ 3.8)	($ 2.4)	38%
LFD	$ 3.79	15.1%	($ 7.9)	($ 5.1)	36%
XD	–	0.0%	($11.0)	($ 7.8)	29%
IS	$ 1.90	38.7%	$ 8.0	$ 7.4	7%
System	$58.56	27.1%	–	–	–

*A positive cross-subsidy value indicates the class is being subsidized; a negative value indicates it is providing the subsidy.
Source: Exhibit IEc-3

5. Rate Design Issues

Q. Please describe the Company's proposed tariff structure for the Rate N/NT distribution services.

A. The current Rate N/NT tariffs recover distribution costs with a flat monthly customer charge and a set of declining block energy charges, which are seasonally differentiated for customers with high volumes. The Company proposes to substantially simplify this tariff, by adopting a tariff with a customer charge and a single volumetric charge. The Company's proposal is summarized in Table IEc-6 below.

Table IEc-6 UGI Gas Proposed Changes to Rate N/NT Distribution Tariff Charges				
		Current	Proposed	Percent Change
Customer Charge	$/mo.	$8.55	$32.00	274.3%
First 25 mcf/month	$/mcf	4.0268	3.6932	-8.3%
Next 475 mcf/month	$/mcf	3.5309		4.6%
Over 500 mcf/month Winter	$/mcf	2.4374		51.5%
Over 500 mcf/month Summer	$/mcf	2.2902		61.3%
Source: Exhibit E				

As shown in Table IEc-6, the Company proposes an enormous increase in the monthly fixed customer charge, but the effect of that increase is partially offset by the change in the tariff block structure. Nevertheless, the proposal would result in enormous percentage rate increases for the smaller customers within the class. For a customer that consumes about 100 mcf of gas per month (about 50 percent above that for the average residential customer), the Company's proposed increase in distribution charges would be nearly 50 percent.

Q. Are there reasons why such a large customer increase could be justified?

A. Yes. First, the CSAS provides information regarding the "customer component" of costs, which can serve as the cost basis for the customer charge. However, the CSAS results must be used cautiously when applied to a heterogeneous class like Rate N/NT. The primary drivers of customer-related costs in the CSAS, namely meters and service lines, vary considerably between smaller customers and larger customers within the class. If the customer charge is set equal to the average customer cost, it will tend to over-recover costs from small customers and under-recover costs from larger customers. Thus, the cost basis for the customer charge for Rate N/NT should be the customer-related costs for small customers within the class, rather than the average customer in the class.

Unfortunately, the CSAS does not have this detail. However, smaller Rate N/NT customers have customer related costs that are similar to those for residential customers. As such, I conclude that the Rate R/RT customer cost serves as a reasonable estimate of customer-related costs for small Rate N/NT customers. In my CSAS, that value is about $29 per customer per month.[26]

In addition, I consulted the Rate N/NT tariffs for UGI Gas affiliates. The current approved customer charges for those NGDCs is $32.41 for UGI PNG and $30.40 for UGI CPG.

Thus, both the cost basis and the approved tariff structure at UGI Gas affiliates supports a material increase in the customer charge.

Q. What, then, is your recommendation for the N/NT class?

A. I conclude that the Company's proposal for an enormous increase in the Rate N/NT customer charge violates the principle of rate gradualism for small customers within the Rate N/NT class. While I believe that a substantial rate increase is justified by both the CSAS results and the Commission-approved tariff design for UGI Gas affiliates, this change would be better achieved more gradually. I propose that the Rate N/NT customer charge be set at no more than $20 per month. As shown in Exhibit IEc-3, at my proposed revenue allocation for the N/NT class, this would require that the commodity charge be set at $3.6707 per mcf.

Under those rates, a small Rate N/NT customer with consumption of 100 mcf per year would see a bill increase of about 20 percent (rather than 50 percent), which would be less than 2 times the average percentage distribution rate increase that I propose for the class.

In addition, if the Commission should reduce the Company's overall revenue requirement, any such reduction that is passed on to the N/NT class (relative to my

[26] Note that I include all costs that are reasonably classified as customer-related in the CSAS for this calculation, which I believe is appropriate for non-residential customers. However, I recognize that the Commission has indicated on several occasions that the cost basis for the residential customer charge should include only "direct" customer costs.

proposed revenue allocation) should be assigned to both the customer charge and the commodity charge.

Q. What is the Company's proposal for tariff charges for Rate DS?

A. Like the Rate N/NT class, the Company proposes to simplify the tariff structure by eliminating the seasonal declining block tariff rates, and replace it with a simple customer/commodity charge approach. Unlike the N/NT class, the Company proposes no increase to the fixed monthly customer charge. The proposal is shown in Table IEc-7 below.

Table IEc-7
UGI Gas Proposed Changes to Rate DS Distribution Tariff Charges

		Current	Proposed	Percent Change
Customer Charge	$/mo.	$290.00	$290.00	0.0%
First 500 mcf/month	$/mcf	2.3000		26.6%
Over 500 mcf/month Winter	$/mcf	2.0700	2.9121	40.7%
Over 500 mcf/month Summer	$/mcf	1.9500		49.3%
Source: Exhibit E				

Q. Do you have any concerns about this proposal?

A. My only observation is that, under the Company's proposed distribution tariffs for Rates N/NT and DS, a significant number of smaller customers that the Company has included in its forecasts for the Rate DS class would pay lower distribution rates under Rate N/NT than they would under Rate DS.[27] While there are other factors which affect a customer's choice of rate class, this relationship suggests that more customers may opt for Rate N/NT retail transportation service over Rate DS transportation service.

Q. Does this breakeven analysis affect your proposed rate design?

[27] In OSBA-I-19, the Company confirms that, under its proposed distribution rates, the breakeven point between Rate N/NT and DS would be average consumption of 330 mcf per month. The Company indicates further than some 272 of 592

A. My revenue allocation proposal for the Rate N/NT and Rate DS classes tends to exacerbate this issue, because it lowers N/NT rates relative to DS rates. Although this effect is offset somewhat by my proposal for Rate N/NT tariff design, the overall impact would be increase the price advantage of N/NT service if the Company's proposed DS tariff design is adopted.

In order to mitigate this problem, one option for the Company would be to reduce the customer charge for Rate DS customers. In the alternative, the Company could consider differentiated customer charges for the DS class, with lower monthly charges for smaller customers. (This approach has been adopted by other NGDCs in Pennsylvania.) Due to the uncertainty regarding the overall revenue requirement, cost allocation, and revenue allocation, I do not have a specific recommendation at this time.

Q. Please describe the Company's proposed Technology and Economic Development ("TED") Rider.

A. As proposed by the Company, the TED Rider is a tariff provision that would essentially allow the Company to establish negotiated rates with any N, NT, DS or LFD customer. It would ostensibly be used to attract new gas load, encourage technology innovation, and support economic development. The rider provisions can take the form of a tariff charge or a credit relative to regular tariff rates. The charge would effectively be used as a replacement for an upfront customer contribution. The credit would apply in cases where the distribution margin generated by new customers exceeds the incremental cost of attaching a new customer, and would be a mechanism to return some of that value to the new customer.

Q. Do you agree with this proposal?

A. Not at this time. I am particularly concerned about the rate discount mechanism, which would appear to provide unfair advantages to new customers at the expense of existing customers. With regard to the potential credits, this mechanism would appear to be a return to the economic development rates of yesteryear.

For the reasons discussed above regarding interruptible rates, I agree all customers can potentially be better off if loads are attracted or retained at revenues that exceed incremental cost. However, these flex rate mechanisms should have the basic protections that I outlined, and the Company's proposal does not establish those protections, and would essentially allow the Company to negotiate rates at will. For example, it is likely that existing business customers of UGI Gas who are paying firm service rates that cover the cost of the existing system would not be pleased by having to face competition from a new customer that is offered discounted gas distribution rates by UGI Gas.

Moreover, the proposal would significantly weaken the protections inherent in the customer contribution policy. Utilities establish customer contribution policies in order to protect existing customers from excessive costs caused by new customers, and to require some reasonable contribution in aid of construction ("CIAC") from new customers to the embedded cost of the existing system.

Under the Company's existing customer contribution mechanism, some new customers will cause the Company to incur more incremental costs than are justified by the revenue from the new customer, and those customers must make an up-front contribution for the difference. In effect, the utility, and eventually the rest of the ratepayers, take the risk that the new customer will continue to provide long-term regular rate revenue to the system, and the customer takes the risk for the contribution. Overall, the addition of this customer provides no net benefit to existing customers, but also causes no harm. The TED Rider, as proposed, would essentially shift more of the risk from the new customer to the existing ratepayers, by reducing the required CIAC and replacing it with a much less certain revenue stream.

In the alternative, under the Company's existing customer contribution policy, some new customers will provide more revenues than necessary to cover the incremental costs of providing service. In effect, these customers will make some contribution to the embedded cost of the existing distribution system. The existing customer contribution policy therefore reflects a balance that some new customers just cover their costs, while other new customers bear some share of the costs of the existing system from which all customers benefit. The credit mechanism in the TED Rider, however, would serve to reduce the contributions to the cost of the existing system from new customers, and shift that value to new customers.

Thus, as proposed, I conclude that the TED Rider proposal is unduly discriminatory and does not contain reasonable economic and competitive protections for existing customers.

6. <u>Energy Efficiency and Conservation Plan</u>

Q. Why has the Company submitted an EE&C Plan in this proceeding?

A. Based on the filed testimony of Mr. Szykman (Statement No. 1) and Mr. Love (Statement No. 11), I identified the following reasons offered by the Company for implementing an EE&C Plan ("Plan"):

- The reduction in consumption from the Plan will provide savings to program participants and put downward pressure on natural gas prices;
- The Plan will serve as a "key element" for Pennsylvania's compliance with the EPA's Clean Power Plan;
- Many other utilities across the country have similar plans, including the Philadelphia Gas Works ("PGW") in Pennsylvania;
- The Plan will contribute to economic welfare in Pennsylvania.

Q. What is the essence of the Company's proposed EE&C Plan?

A. The Company's EE&C Plan will identify the potential for cost-effective energy conservation and efficiency, and it will provide subsidies to those customers who participate in the Plan. The costs of those subsidies plus all plan operating and administrative costs will be recovered from other ratepayers. In general, EE&C plans generally attempt to implement economically efficient conservation measures that would not be undertaken in the absence of a plan. Overall economic efficiency is measured by a Total Resource Cost ("TRC") Test, which generally compares the longer-term incremental costs avoided by a particular with the near-term incremental costs of the program (including both utility and participant costs).

Q. Is this an altruistic proposal by the Company?

A. While there may be altruistic aspects to the Company's proposal, they do not appear to extend to the Company actually offering to make a contribution to the costs of operating the plan or subsidizing the plan's beneficiaries. The Company proposes that the entire cost of the plan be borne by ratepayers. Moreover, with the proposed rate reconciliation mechanism, the Company faces virtually no risk that it would not fully recover the program costs it incurs. Moreover, unlike the plans mandated by Act 129 for electric distribution companies ("EDCs"), the UGI Gas proposed plan would have no penalties for failing to achieve minimum load reductions.

Q. The Company describes its EE&C Plan as voluntary. Is it a voluntary plan?

A. I understand from OSBA counsel that the proposed plan is voluntary in that the Company has no legal obligation to develop and implement an EE&C Plan. However, from a ratepayer standpoint, the plan is involuntary, in that the tariff charges imposed on ratepayers to fund all program costs and subsidies, are non-bypassable, save by switching to an alternative fuel or closing up shop.

Q. Are there sound economic reasons for ratepayer-subsidized energy conservation plans?

A. In some circumstances there are. First, it is often argued that energy prices do not reflect the full social cost of energy consumption, namely the "externalities" related to environmental impacts. However, because Pennsylvania generally does not recognize non-monetary costs in its economic evaluation of EE&C programs, this rationale generally does not apply. Second, it is often argued that customers do not make economically efficient choices with respect to energy conservation, due either to market failures or insufficient customer education. For small businesses, market failures that may contribute to sub-optimal investment in energy conservation include customers' high capital costs or capital constraints, customers' short term planning horizons, and landlord-tenant issues.[28] By providing subsidies, a ratepayer financed EE&C plan may result in overall gains in economic efficiency, with the gains from the winners outweighing the negative impacts on the losers.

Q. Are there economic disadvantages to EE&C plans?

A. Yes. By providing subsidies for energy conservation, the utility may simply be displacing conservation efforts that would have been undertaken without the subsidies ("free riders"). Similarly, the subsidized conservation programs may actually cause customers to delay making economically efficient conservation investments, simply in order to wait until they become eligible for the subsidy. From a competitive standpoint, a subsidized conservation program can possibly have the effect of discouraging competitive suppliers from integrating into the energy conservation markets, because they are unable to mandate cross-subsidies from captive ratepayers, as can the utilities. Similarly, conservation vendors who are not chosen by the utility to participate in the subsidized programs are also at a competitive disadvantage, because they also have no way to recover subsidies.

And, of course, utility conservation programs are fundamentally inequitable, in that utility ratepayers who do not participate in the program (or who have made efficient conservation investments without subsidies) are required to subsidize those who do.

Q. Does OSBA oppose the Company's adoption of an EE&C Plan?

A. I am advised by counsel that OSBA does not. The Commission has approved "voluntary" EE&C plans at other Pennsylvania NGDCs, including PGW and Company-affiliate UGI CPG (in its 2011 base rates proceeding). OSBA's interests are limited to trying to ensure that non-participant costs are not excessive, the programs are economically efficient, the programs are targeted at customers who would otherwise not

[28] A common landlord/tenant issue arises when the tenant has responsibility for the electric bill and therefore benefits from the savings from an EE&C investment, but has a lease term that is much shorter than the period over which the investment provides value. If the tenant decides to move, or even has to renegotiate the lease, the value of the EE&C investment implicitly shifts to the landlord. Thus, landlords may be unwilling to invest in EE&C measures because the tenant initially gets the benefit, and tenants are unwilling to invest because they do not perceive a long enough time horizon to make the investment worthwhile.

invest in conservation, beneficiaries of the programs make a reasonable contribution to the cost of those programs, and that the cost recovery mechanism is reasonable.

Q. **What are the major components of the Company's proposed plan for non-residential customers?**

A. The Company proposes the following basic programs:

- Nonresidential Prescriptive ("NP"): Subsidies for new and replacement equipment, primarily gas using heating equipment and appliances.

- Nonresidential retrofit ("NR"): Subsidies for building-wide retrofits, for commercial buildings and master metered multifamily buildings.

- New construction ("NC"): Subsidies for builders/developers to install high efficiency equipment.

- Combined heat and power ("CHP"): Subsidies for projects where "waste" heat from process operations is used to generate electric power.

The first three programs apply only to the Rate N/NT classes, while the CHP program would apply to Rates N/NT, DS, and LFD.

Q. **For the non-residential programs, is the overall proposed non-participant cost reasonable?**

A. UGI forecasts that "utility" annual costs for non-residential programs will be $0.89 million in FY 2017, and rise to $2.27 million in FY 2021. Based on the Company's proposed distribution rates for the future test year, this spending amounts to 0.9 percent to 2.3 percent of *distribution* revenues. Since Act 129 establishes an overall cap for electric industry programs of 2 percent of *total* revenues, the Company's proposed spending for the non-residential programs appears to be reasonably modest.

Moreover, on a per-mcf basis, the costs of the plan for non-residential customers starts at less than 3 cents per mcf, and would grow to about 7 cents per mcf by 2021 (if load growth is assumed to be zero). These unit charges are well below the comparable charges for residential customers, implying that the utility costs are not unduly targeted at the non-residential sector.

Q. Are the non-residential programs economically efficient?

A. My mandate for this proceeding does not extend to a conducting an in-depth assessment of the Company's cost-benefit calculations. As such, I can only report the Company's calculations. With that caveat, however, the Company relies on a Total Resource Cost ("TRC") Test methodology to determine whether the avoided energy costs of the program exceed the overall costs of the program (including both utility and participant costs). Even without the Company's dubious inclusion of hypothetical carbon tax costs and demand reduction induced price effects ("DRIPE") in its calculations, each of the non-residential programs exhibits a benefit-cost ratio in excess of unity.[29]

Q. Do you agree with the Company's inclusion of carbon taxes and DRIPE in the TRC Test?

A. No. Neither approach is supported by the economics. Moreover, while the Company reports that its TRC Test calculations are generally consistent with Commission policy, the inclusion of these factors certainly appears to conflict with established practice.[30]

Regarding the inclusion of a benefit associated with a future carbon tax, this assumption appears to be speculative. I am simply much less optimistic than is the Company that either the United States or Pennsylvania will adopt a carbon tax in the near future. In general, the Commission appears to agree. With respect to the parameters for the TRC Test, the Commission has stated:

> *"We shall not include societal costs, environmental costs, NEIs or other non-electric elements into the 2016 TRC Test except to the extent discussed above*

[29] See Attachment OSBA-I-28.2.

[30] In its most recent EE&C filing, PGW proposed to include benefits associated with a carbon tax and DRIPE, to which I submitted opposition testimony. The methodology was approved by the administrative law judge in that proceeding, and the OSBA did not taken exception to those findings. See Docket No. P-2014-2459362. However, I am advised by counsel that, consistent with a long history of Commission precedent, the OSBA considers PGW to be *sui generis*, and that decisions regarding PGW on this issue have no bearing on other NGDCs. I am advised that OSBA counsel intends to address this issue in its briefs in this proceeding.

relative to quantifiable benefits from fossil fuels and water avoided costs." Order M-2015-2468992 entered June 22, 2015, p 14.

"Any carbon-related reduction expense not currently included will continue to be excluded until such time as legislation is passed that dictates otherwise." Order M-2015-2468992 entered June 22, 2015, p 29.

Regarding DRIPE, it is likely true that any reduction in the aggregate demand for natural gas in North America will have some impact on prices, as more expensive sources of natural gas are forced out of the market. However, while this reduction in prices is a benefit to gas customers, that benefit is offset by the loss to gas producers. In economic terms, this is a gain in consumer surplus offset by a reduction in producer surplus. Since Pennsylvania is a major net exporter of natural gas, the economic impact on Pennsylvania of natural gas price suppression is likely to be net negative, not net positive. As a matter of public policy, it does not appear to be sensible to claim a benefit associated with reduced natural gas prices without recognizing the concomitant impact of those price reductions on Pennsylvania employment, lease payments, royalties, taxes, etc. in the gas producing industry.

Moreover, in this respect, I did not locate any policy adopted by the Commission with respect to the TRC Test which includes price suppression benefits associated with reduced energy consumption.[31]

Q. Are participating customers making a reasonable contribution to the costs of the plans from which they benefit?

A. For each non-residential program, Table IEc-8 below provides a comparison of the utility cost and the participant cost of the program summed over the five years of the plan, with

[31]The Commission appears to have at least briefly considered price suppression benefits for electricity "demand response" programs, focused on reducing peak electrical demand. I was unable to locate any Commission language supporting the recognition of price effects related to overall reduction in energy consumption, which is what UGI Gas proposes in this proceeding. Moreover, even for DR programs, the Commission has not adopted any price suppression benefits in the TRC Test. For example: "*However, due to the lack of quantifiable information regarding such suppression in prices, we will not prescribe a specific PA TRC calculation method at this time. Such benefits may be included in the PA TRC calculations for any proposed residential demand response programs. We strongly encourage the EDCs and stakeholders to review the potential for wholesale market price suppression due to residential demand response measures.*" Order, M-2012-2300653/M-2009-2108601, page 60, entered August 30, 2012. I was not able to locate any subsequent Commission rulings on this subject.

the utility cost split between incentives and program operating/administrative costs. While it is difficult to establish hard-and-fast rules about what constitutes a reasonable contribution from participants, Table IEc-8 suggests that the proposed participant contribution in the NR program are marginal at best, with subsidies representing more than two-thirds of the program costs, and that the participant contribution for the NC program is inadequate, with ratepayers being asked to pay for over 85 percent of the program costs.[32]

Table IEc-8
Summary of Proposed Non-Residential EE&C Program Costs (Full Five Years)
$000

	O&M/A&G	Incentive	Participant	Total	Participant %
NP	657	1,683	2,537	4,877	52.0%
NR	768	459	554	1,782	31.1%
NC	626	521	193	1,341	14.4%
CHP	795	2,000	56,261	59,056	95.3%
Portfolio	620	0	0	620	0.0%
Total	**3,466**	**4,664**	**59,545**	**67,675**	**88.0%**
NP/NR/NC	2,051	2,664	3,284	8,000	41.1%

Source: Exhibit IEc-3, OSBA-I-29

I therefore recommend that the Company present evidence as to why the subsidies for the NR and NC programs need to represent such a large share of overall program costs in its rebuttal testimony. Absent a clear demonstration that there is a need for such substantial subsidies, I recommend that the Commission direct the Company to modify its EE&C Plan such that the "utility" costs not exceed 50 percent of the costs for any of the non-residential programs.

Q. How does the Company propose to recover the "utility" costs from ratepayers?

A. For the purposes of cost recovery, UGI Gas proposes to establish two rate class groups: residential and non-residential. The non-residential group includes customers in Rates N/NT, DS, and LFD (and therefore excludes Rate XD and Interruptible customers).

[32] This latter result may relate more to how participant costs are categorized in the Company's calculations, as it may not be readily obvious what costs are being borne by the participant in new construction.

Costs for each program will be assigned to the rate class group that benefits from the program. Portfolio-wide costs are allocated between the two rate class groups.[33]

The total costs for each rate class group would then be recovered in a volumetric charge specified in the proposed Energy Efficiency and Conservation Rider, starting at 7.78 cents per mcf for residential and 2.78 cents per mcf for non-residential. These charge values will presumably increase by a factor of between 2 and 3 over the proposed five-year term of the EE&C Plan. The Company proposes that this recovery mechanism be fully reconcilable by rate class group on an annual basis, with any difference between actual plan costs and actual plan revenues being added to the cost basis for the next year's EE&C charge.

Q. Do you have any objections to this proposed mechanism in this proceeding?

A. I do. From a cost causation standpoint, it is not possible to recover all the costs from the customers who benefit from the program, since the cross-subsidization lies at the heart of these programs. Thus, the normal rules for rate design cannot apply to this cost item, as it is more akin to a tax than a tariff charge.

With that caveat, I agree that breaking up the programs into rate class groups is generally consistent with the requirements of Act 129 for EDCs, and it at least has the advantage of not requiring business customers to cross-subsidize residential programs and vice versa.[34] Nevertheless, the Company indicates that the NP, NR, and NC programs apply only to the Rate N/NT class, while the CHP applies to N/NT, DS and LFD. This indicates both that the Company's plan has different strategies for smaller and larger non-residential customers, and that the costs associated with smaller customers are likely to be proportionately higher. In addition, to my knowledge, most other EE&C programs in Pennsylvania segregate non-residential EE&C costs between small and large non-

[33] At this writing, it is not clear to me how the $3.8 million in portfolio-wide administrative costs are allocated. Based on the values in OSBA-I-29, it appears that the ratio of portfolio-wide costs to "utility" costs is somewhat higher for the residential class than for the non-residential class. It is therefore possible that costs are over-assigned to the residential class. Doubtless the Company will explain this anomaly in its rebuttal testimony.

[34] Of course, businesses will subsidize other businesses, and residential customers will subsidize other residential customers.

residential customers. I therefore recommend that the Company both track costs and develop separate charges for the small non-residential customers (Rates N/NT) and the large non-residential customers (Rates DS and LFD).[35] Exhibit IEc-3 shows the implications of such a segregation for 2017 EE&C charges, based on the assumption that all CHP costs will apply to the DS and LFD classes, while all NP, NR and NC costs apply to Rate N/NT.

As to the issue of tariff design for these costs, I agree with the Company that a flat energy tariff charge is not an unreasonable mechanism, in that it will tend to function as a small tax on gas consumption, and thus further discourage natural gas use in the Company's service territory.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[35] In making this recommendation, I advised OSBA counsel that this recommendation would generally serve to increase charges to small business customers. Counsel advises that OSBA supports this recommendation as a matter of principle, and that it is consistent with established policies of the office.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 30 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 20 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in electric and gas industry regulatory matters. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has worked for state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For nearly twenty years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development and preparation of public policy positions, litigation strategy, and longer term strategy.

For the **INDUSTRIAL GAS USERS ASSOCIATION**, Mr. Knecht provided consulting and expert witness services in a generic cost allocation proceeding involving Gaz Métro before the Régie de l'énergie in Québec.

For the **NEW BRUNSWICK PUBLIC INTERVENER**, Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving Enbridge Gas New Brunswick. Mr. Knecht's testimony has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, over the past fifteen years, Mr. Knecht has provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2015-2501500	Pennsylvania Public Utility Commission	Philadelphia Gas Works	October 2015	Pennsylvania Office of Small Business Advocate	DSIC rate design under cash flow regulation, capital structure
P-2014-2459362	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2015	Pennsylvania Office of Small Business Advocate	Demand side management programs, rate decoupling mechanism, incentive mechanism, cost-benefit analysis.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2015	Pennsylvania Office of Small Business Advocate	Misc. revenue requirement issues, cost allocation, rate design
R-2015-2468056	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2015	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, customer contribution policy
R-2015-2461373	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	April 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-2014-2456648	Pennsylvania Public Utility Commission	Peoples TWP LLP	March 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-3867-2013	Régie de l'énergie, Québec	Société en commandite Gaz Métro	February 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation
R-3888-2014	Régie de l'énergie, Québec	Hydro Québec TransÉnergie	December 2014	AQCIE/CIFQ	Transmission customer contribution policy
R-2014-2428744 R-2014-2428742	Pennsylvania Public Utility Commission	Pennsylvania Power Company, West Penn Power Company	November 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
M-2014-2430781	Pennsylvania Public Utility Commission	PPL Electric Utilities	October 2014	Pennsylvania Office of Small Business Advocate	Smart meter procurement, rate design
Matter No. 253	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates
Matter 225	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories ("gas-on-gas").
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program ("GET Gas")
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates
P-2011-2256365	Pennsylvania Public Utility Commission	PPL Electric Utilities	November 2011	Pennsylvania Office of Small Business Advocate	Default service reconciliation
Matter No. 132	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	October 2011	*New Brunswick Public* Intervenor	Revenue requirement, cost forecasting, *system expansion economic test*, regulatory deferral test, filing requirements.
R-2010-2161694 *on Remand*	Pennsylvania Public *Utility Commission*	PPL Electric Utilities	August 2011	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2011-2238943, R-2011-2238943, R-2011-2238949,	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2011	Pennsylvania Office of Small Business Advocate	Design day demand, mandatory capacity assignment, sharing mechanisms
C-2011-2245906, M-2011-2243137	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2011	Pennsylvania Office of Small Business Advocate	Reconciliation of default service costs and revenues
P-2011-2218683, P-2011-2224781	Pennsylvania Public Utility Commission	*West Penn Power Company*	April, May 2011	Pennsylvania Office of Small Business Advocate	Critical peak pricing, time-of-use pricing

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2010-2214415	Pennsylvania Public Utility Commission	UGI Central Penn Gas	April 2011	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, revenue allocation, non-residential rate design, EE&C cross-subsidies and cost recovery, natural gas vehicle subsidies
R-2010-2215623, R-2010-2201974	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	April 2011	Pennsylvania Office of Small Business Advocate	Cost of equity capital, cost allocation, revenue allocation, BTU adjustment mechanism, rate design, DSIC
NBEUB 2010-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	April 2011	New Brunswick Public Intervenor	Cost- and market-based ratemaking, transition mechanism
M-2010-2210316	Pennsylvania Public Utility Commission	UGI Utilities, Electric Division	March 2011	Pennsylvania Office of Small Business Advocate	Energy efficiency plan cost recovery, conservation development rider
A-2010-2213893, et al.	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	February 2011	Pennsylvania Office of Small Business Advocate	Asset valuation, reasonableness of proposed affiliate transaction
M-2009-2123944	Pennsylvania Public Utility Commission	PECO	January 2011	Pennsylvania Office of Small Business Advocate	Dynamic pricing cost allocation and rate design
NBEUB 2010-007	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	December 2010	New Brunswick Public Intervenor	Allowable costs, O&M capitalization policy, expansion cost effectiveness, incentive mechanisms
R-3740-2010	Régie de l'énergie, Québec	Hydro Québec Distribution	December 2010	AQCIE/CIFQ	Pension cost reconciliation, cross-subsidies, rate design
P-2010-2158084	Pennsylvania Public Utility Commission	West Penn Power Company	November 2010	Pennsylvania Office of Small Business Advocate	Transmission service charge, reconciliation timing
P-2010-2194652	Pennsylvania Public Utility Commission	Pike County Light & Power	November 2010	Pennsylvania Office of Small Business Advocate	Electric default service procurement, customer education
A-2010-2176520, A-2010-2176732	Pennsylvania Public Utility Commission	Allegheny Power/FirstEnergy Corporation	September 2010	Pennsylvania Office of Small Business Advocate	Implications of proposed merger for default service

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
App. No. 1605961, Proceeding ID 530	Alberta Utilities Commission	Alberta Electric System Operator	August 2010	BC Hydro	Transmission rate design
R-2010-2167797	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	July 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables, rate of return
R-2010-2172933, R-2010-2172922, R-2010-2172928	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
NBEUB 2010-002	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	June 2010	New Brunswick Public Intervenor	Cost allocation, rate design, deferral costs
R-2010-2161694	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2010-2161920	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, retainage rates, gas price forecasting
R-2009-2149262	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, rate of return
P-2009-2145498	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division)	April 2010	Pennsylvania Office of Small Business Advocate	Merchant function charge, purchase of receivables
R-2010-2157062	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
NBEUB 2009-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	March 2010	New Brunswick Public Intervenor	Cost allocation, deferral costs
R-2009-2139884	Pennsylvania Public Utility Commission	Philadelphia Gas Works	March 2010	Pennsylvania Office of Small Business Advocate	Revenue requirement, cost allocation, rate design, DSM program

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010-2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2010-2150861	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
R-2009-2145441	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
P-2010-2099333	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	February 2010	Pennsylvania Office of Small Business Advocate	Purchase of receivables

Note: Dates shown reflect submission date for direct testimony.

October 2015

EXHIBIT IEc-2

REFERENCED INTERROGATORY RESPONSES

I&E-RS-61-D

OSBA-I-2

OSBA-I-3

OSBA-I-4

OSBA-I-5

OSBA-I-6

OSBA-I-8

OSBA-I-10

OSBA-I-15 [CONFIDENTIAL]

OSBA-I-19

OSBA-I-20

OSBA-I-28

OSBA-I-29

OCA-IV-8

OCA-IV-20 [CONFIDENTIAL]

OCA-IV-22 [CONFIDENTIAL]

Note: Due to the electronic nature of both the responses and many attachments in the Company's "DREAM" system, copies of the responses are not attached to this testimony. I am advised by counsel that OSBA will undertake the necessary steps to have these responses entered into the record in this proceeding during the hearings in this matter.

EXHIBIT IEc-3

[CONFIDENTIAL]

RDK MODIFIED COST OF SERVICE ALLOCATION STUDY

DIRECT TESTIMONY VERSION

OSBA Statement No. 2
PUBLIC VERSION
6/2/16 Hg TK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2015-2518438
UGI UTILITIES, INC. (Gas Division)	:	

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: May 10, 2016

Date Submitted for the Record: ____________________

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

I. <u>Introduction</u>

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in the proceeding and my qualifications were presented therein.

Q. What issues do you address in this rebuttal testimony?

A. At the request of OSBA, this rebuttal testimony addresses various aspects of the direct testimony submitted by the following witnesses:

- Mr. Glenn A. Watkins, representing the Pennsylvania Office of Consumer Advocate ("OCA") on matters of cost allocation and revenue allocation;
- Mr. Ethan H. Cline, representing the Commission's Bureau of Investigation and Enforcement ("I&E"), on matters of cost allocation, revenue allocation and rate design;
- Mr. James L. Crist, representing Dominion Retail, Inc., Shipley Choice, LLC, Interstate Gas Supply, Inc., Amerigreen Energy, and Rhoads Energy (collectively, "NGS Parties"), regarding the gas procurement charge ("GPC");
- Mr. Orlando Magnani, representing the Retail Energy Supply Association ("RESA"), on matters relating to gas supply costs in general and pipeline capacity assignment in particular, as well as the GPC.

Q. Do you have any introductory comments?

A. I do. From a rate design standpoint, this case contains a number of unusually complicated features.[1] Utility rate design must necessarily follow from (a) a determination of the utility test year revenue requirement, (b) estimation of revenues at

---

[1] Both Mr. Cline and Mr. Watkins recognize this unusual complexity. See, for example, OCA Statement No. 3 at page 16 lines 1 to 15 and I&E Statement No. 5 at page 32 lines 4 to 12.

present rates, (c) allocation of costs to the various rate classes, and (d) allocation of the rate change among the various rate classes. This case starts out as being unusually complex, in that there are enormous differences among the parties with respect to both the utility revenue requirement and the estimation of revenues at present rates. UGI Gas forecasts a need for $58.6 million in *additional* revenues, whereas OCA and I&E calculate that base rate revenues at current rates should be *reduced* by $27.1 million and $18.6 million respectively.

These differences cast significant doubt on the usefulness of any cost allocation analysis. Traditionally, cost allocation analysis is undertaken at the utility's forecast volumes and claimed revenue requirement. In this case, however, the large differences among the parties with respect to class volumes cast significant doubt on the usefulness of all volumetric and demand allocation factors used in the Company's cost allocation analysis. Moreover, the significant differences among the parties regarding certain cost items further reduces the relevance of using the Company's claimed revenue requirements in the cost allocation analysis.

This case is then further complicated by some significant changes in the makeup of the non-residential classes. As shown in Exhibit E, the Company assumes that, under its proposed rate classes, a significant portion of non-residential customers are expected to shift rate classes, in order to take service at the most favorable rates. For example, the Company calculates that nearly half the Rate DS load will be from customers who currently take service in Rate N/NT. This calculation is presumably based on the Company's proposed revenue allocation and rate design for those two classes. If, however, the Commission determines that the revenue allocation to those two classes should be substantially different than that proposed by the Company, or if the rate design for either class should be substantially different, it is likely that the makeup of the classes would also be substantially different. This, in turn, would affect cost and revenue allocation. In effect, there is a circularity problem for which linear regulatory proceedings are not well-suited.

Given the substantial differences between the parties with respect to the overall revenue requirement and current-rate revenues, and the significant impact the various recommendations would have on allocated cost, a reasonable regulatory approach would be to bifurcate the proceeding (an approach which some jurisdictions use). The first stage would resolve the revenue requirement, current-rates revenue, and the key cost allocation *methodological* issues.[2] If those are resolved, a follow-up focused proceeding could then implement the cost allocation method, and address revenue allocation and rate design.

However, based upon the advice of counsel and on my long experience in Pennsylvania, I understand that it is very unlikely that such a process will be adopted. In effect, we will muddle through this process using the best information available, and the Commission will make its best effort at pulling together all of this complexity into a coherent decision. In light of this complexity, however, it may make sense to include a provision for a mandatory *ex post* review process, in the form of a stakeholder collaborative or a required report from the Company. In particular, I suggest that the Commission mandate a review of how actual loads and actual customer migration among rate classes compare to the assumptions used by the Commission in reaching its decision in this proceeding. Ideally this review would take place well after the end of the test year, perhaps in the middle of 2018. If the actual load information proves to be substantially different than the assumptions used by the Commission in this proceeding, a follow-up proceeding should be initiated.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 addresses various cost allocation issues raised by Mr. Watkins and Mr. Cline;
- Section 3 reviews the revenue allocation proposals of Mr. Watkins and Mr. Cline, and includes an update for the recommendations in my direct testimony

[2] Key cost allocation methods in this proceeding are segregation of mains by size, classification and allocation of mains costs, direct assignment of costs to large customers, and cost allocation treatment of interruptible loads.

regarding revenue allocation if the Commission determines that (a) the Company's filing vastly understates the current-rates revenue for Interruptible Service customers as argued by both Mr. Watkins and Mr. Cline, and (b) that a material rate decrease should be imposed.

- Section 4 briefly addresses Mr. Cline's rate design recommendations for the Rate N/NT classes.
- Section 5 addresses various issues involving the competitive playing field between competitive natural gas suppliers ("NGSs") and the Company, including the gas procurement charge ("GPC") and the allocation of upstream capacity.

2. <u>Cost Allocation</u>

Q. Beyond the positions in the Company's filing and your own direct testimony, what are the positions of the parties in this proceeding regarding cost allocation methods?

A. Mr. Watkins expresses disagreement with a number of aspects of the Company's proposed methods for allocating gas distribution mains costs. Also, because he concludes that the Company's current-rates revenues are vastly understated, he prepares an alternative cost allocation study based on certain proposed adjustments to current-rate revenues. Mr. Cline concludes that the Company's cost allocation study presented in Exhibit D is the appropriate method for allocating mains costs to interruptible customers. He rejects the use of the Company's cost allocation study in Exhibit D-1 which assigns zero mains costs to all interruptible customers except the one very large customer.

Q. Do you agree with Mr. Cline's recommendations regarding cost allocation methodology?

A. I agree that the Company's use of a modified A&E allocation factor in Exhibit D for assigning mains costs to interruptible customers is not unreasonable, with the proviso that there are likely to be a range of methods for allocating mains costs to interruptible customers that are imperfect but not unreasonable. However, I disagree with Mr. Cline's reliance on the Company's cost allocation methods with respect to the issues that I address in my direct testimony. As Mr. Cline does not present any affirmative defense of those methods beyond that in the Company's filing, there is no need for further rebuttal.

Q. Are there any areas in which you, Mr. Watkins and Mr. Cline adopt similar recommendations regarding changes to the Company's cost allocation methodology?

A. Yes. Mr. Watkins and I agree that the Company has not justified the proposed "bifurcation" of mains into small main and large main categories. All three intervenor cost allocation witnesses reject the Company's proposed cost allocation method which assigns zero mains costs to interruptible customers as being inconsistent with the actual usage of the distribution system by those customers.

Q. In his direct testimony, Mr. Watkins rejects the Company's proposed direct assignment of mains costs to Rate XD and the one large interruptible customer. Please comment.

A. Regarding the firm XD customers, Mr. Watkins concludes that, to a significant extent, these large customers are located at a substantial distance from interstate pipeline gate stations, that they have no practical ability to bypass the Company and take service directly from the pipelines, and they rely on mains that serve multiple other customers in various different rate classes. He concludes that these customers are therefore similar to all other gas distribution system customers, and should be subject to the same basic mains cost allocation methodology.

To a large extent, I agree with Mr. Watkins' points. I agree with his observations regarding the nature of the distribution system that is used to serve these customers, and I agree, at least as a theoretical matter, that the same cost allocation methodology should be applied to these customers as to other distribution system customers.

Where we part company relates to the preferred method to use for allocating distribution system mains costs. Mr. Watkins advocates the continued use of one of the traditional cost allocation methods, which applies an arithmetic allocation factor to all mains costs and all customer classes, regardless of the specific size and length of the pipes that actually provide service to individual customers. In my view, the method used by the

Company in its 1995 base rate case is far superior to any proposed method in this proceeding, in that it assigned the costs of specific assets to those customers who used the assets, for *all* of the firm service customers on the system. As such, it is a far more accurate method than any traditional formulaic method. Traditional allocation methods are essentially arithmetic exercises, with no recognition of the actual topography of the distribution system. For example, the traditional methods have no way of reflecting the differences in costs between serving commercial customers that are located in relatively dense commercial districts and can be served at relatively low cost by larger and more cost effective mains, and the costs to serve more remote commercial customers of the same size that require long and relatively high-cost main extensions. Because none of the traditional methods can reflect the cost issues that result from the specifics of customer location and load size, regulators are essentially reduced to trying to decide which arithmetic approximation provides the least unreasonable result.

Thus, data permitting, I support a direct assignment approach for all customers. Since the Company has chosen not to continue to undertake this analysis, I conclude that applying that approach to one class is moderately better than applying it to no classes at all, and I therefore did not object to the Company's use of this method for the firm XD customers. I note also that, in my experience in Pennsylvania, gas distribution rates for large industrial customers are not set based on the traditional cost allocation methods favored by the Commission. Instead, rates for large customers are either based on costs derived from a direct assignment costing method, or are based on a negotiated "flex" rate policy in which rates are set that reflect bypass or alternative fuel capabilities. That the traditional cost allocation method used by the Commission is effectively useless for setting rates for large industrial customers is an indicator that the Commission's preferred method does not reasonably reflect cost causation.

Regarding the large interruptible customer, I am unsure why Mr. Watkins rejects direct assignment, as that customer appears to meet Mr. Watkins' criteria for direct assignment.[3] Based on my review of the Commission's decision at Docket A-2010-

[3] OCA Statement No. 3, page 27, lines 3-9.

2210236, it appears that this customer is served by a dedicated feeder main that is interconnected to an interstate pipeline. As such, I conclude that direct assignment of costs is appropriate for this customer.

Finally, I should note that the debate on this issue is essentially academic, at least for this proceeding. The Company, Mr. Watkins, Mr. Cline and I basically adopt the Company's proposal to set the test year revenue for these customers based on the current rates that have been negotiated with each customer. As such, the cost allocated to this class has little impact on revenue allocation and rate design.

Q. In his direct testimony, Mr. Watkins advocates the use of a 50/50 peak-and-average ("P&A") allocation method for mains costs, in place of the Company's proposed use of an average-and-excess ("A&E") approach. Do you agree with Mr. Watkins proposed change?

A. For the reasons detailed in my direct testimony, I do not believe that either the A&E method or the P&A method is representative of cost causation for gas distribution mains, in that neither method reflects the real-world need for UGI Gas to interconnect all of the customers, and both methods incorrectly assume that mains cost causation is correlated with annual volume. If a traditional method is used, one that incorporates a customer component in the cost allocation method is likely to be more representative of actual cost causation.

However, from a practical perspective, the recommendation in my direct testimony to accept the A&E method was based on Commission precedent. As detailed in my direct testimony at page 9 footnote 6, the most recent Commission precedent for NGDCs is to use the A&E allocation method. Based on the cases cited, I must disagree with Mr. Watkins' statement that the Commission has a ". . . long accepted practice and policy of utilizing a 50%/50% weighting between peak demand and average demand."[4] The more recent Commission precedent supports the use of the A&E allocation factor.

[4] OCA Statement No. 3 at 32.

Q. What is Mr. Watkins' view regarding the allocation of mains costs to interruptible service customers?

A. Consistent with his overall approach to mains costs allocation, Mr. Watkins advocates the use of a 50/50 weighted P&A method for allocating costs to that class. Mr. Watkins concludes that a significant share of demand-related costs should be assigned to interruptible customers, as the Company appears to provide significant gas supply to these customers during peak periods. He uses a class peak demand of 80,000 mcf/day in developing the P&A allocator for this class, which is below the class average day demand of 138,000 mcf/day.

Q. Do you agree with Mr. Watkins' proposed approach?

A. For the reasons detailed in my direct testimony, I do not believe that there is a perfect approach for allocating mains costs to interruptible customers. Mr. Watkins' approach is therefore not necessarily unreasonable, in that he attempts to balance many of the same considerations that I identified in my direct testimony.

Nevertheless, there are two reasons why Mr. Watkins' approach is not suitable for this proceeding. First, in developing his P&A allocation factors, Mr. Watkins appears to include loads and peak demands associated with the very large interruptible customer. As discussed above, I conclude that direct assignment of costs for that customer is a more reasonable method. Second, also as noted above, Mr. Watkins' uses a P&A approach for mains cost allocation, which is not consistent with recent Commission precedent that supports the A&E approach. Moreover, the A&E approach used by the Company in Exhibit D implicitly assumes that the peak day demand for interruptible customers equals the average day demand. As Mr. Watkins assumes that peak day demand is below average day demand, using the A&E method with his parameters would serve to reduce costs allocated to interruptible customers. For the reasons detailed in my direct testimony, I do not agree that such a result is reasonable.

Finally, it should also be recognized that cost allocation for interruptible customers has only limited relevance for revenue allocation and rate design in this proceeding, unless the Company's revenue requirement approach is adopted. As I discuss further below, the

Company proposes to set current-rates interruptible service revenues at allocated costs, using an average of its two cost allocation methods. This is absurd, since current-rate revenues should be set based on current-rate revenues, not allocated costs. Beyond the Company's position, Mr. Cline, Mr. Watkins and I (as discussed below) generally conclude that revenues required from interruptible customers in this proceeding should reflect the current negotiated rate agreements with those customers. As such, the choice of cost allocation methodology will have little impact on revenues assigned to interruptible customers.

3. <u>Revenue Allocation</u>

Q. What are the positions of the parties regarding revenue allocation in this proceeding?

A. In addition to the Company's filed position and the recommendations in my direct testimony, both Mr. Watkins and Mr. Cline offer alternative revenue allocation proposals.

Mr. Watkins bases his revenue allocation recommendations on a reduced overall increase of $42.1 million, consistent with his conclusions that the Company's current-rate revenues are understated by $16.4 million. In making his recommendations, Mr. Watkins relies on the results of his cost allocation study, and he applies the principle of rate gradualism by limiting the maximum increase to 1.5 times the system average increase to the R/RT class, producing an increase of $31.8 million.[5] Mr. Watkins then shares the remaining revenue the other non-flex-rate classes in proportion to the recommendations from the Company. While he expresses concerns about the need for revenue increases from Rate XD and Interruptible customers, Mr. Watkins accepts the Company's proposed flex rate revenues for those classes.

At the full rate increase requested by the Company, Mr. Cline appears to accept the Company's proposed revenue allocation, but does offer an alternative rate design for recovering the revenues assigned to each class.

---

[5] In applying this rule, Mr. Watkins uses the system average percentage increase based on the Company's current-rates value of $216.1 million (average increase of 19.5%), rather than his proposed current-rates value $232.5 million (which would imply a system average increase of 18.1%). This method has the effect of producing a modestly higher revenue increase ($2.2 million) for Rate R/RT.

Q. Please address the issue of current-rates interruptible revenues, as presented in intervenors' testimony.

A. Both Mr. Cline and Mr. Watkins conclude that the Company has inappropriately used allocated cost as a proxy for interruptible class current-rate revenues, by using a value of $4.9 million compared to historical revenues in the $19.6 to $26.6 million range and the Company's actual budget revenues of $20.6 million.[6] This understatement of current-rate revenues serves to overstate the Company's need for an annual base rate increase by approximately $15 million.

Q. Please address Mr. Watkins' proposed adjustment to Rate DS and Rate LFD transportation service charges.

A. Mr. Watkins observes that the Company's current-rate revenues exclude some $1.99 million in base rate margin revenues from transportation customers related to pooling and system access services, that it would earn under the existing tariff. The vast majority of these revenues are related to Rate DS, as shown in UGI Gas Exhibit DEL-3(i). Mr. Watkins goes on to conclude that, if the Commission agrees with the Company's proposal to eliminate these charges, the lost revenue would need to be recovered in other base rates (along with whatever revenue increase is assigned to the class).

Q. Do you agree with the current-rates revenue adjustments recommended by these intervenors?

A. Generally, I do. Regarding interruptible service revenues, I raised the issue of the inconsistency between budget and claimed revenues in my direct testimony, but made no explicit adjustment. Prior to this proceeding, I have never had the experience of participating in a proceeding in which a utility understated its current-rate revenues by a factor of 4, and I was unsure that I had interpreted the Company's filing correctly. However, based on the testimony of Mr. Cline and Mr. Watkins, as well as a more detailed review of the supporting documents, I conclude that Messrs. Cline and Watkins are correct, and the Company has indeed vastly understated its current-rate interruptible service revenues. I therefore agree that a reasonable test year forecast for current rates

[6] See OCA Statement No. 3 at 6-7.

interruptible distribution revenues should be in the range of the $19.4 to $20.4 million estimated by Messrs. Watkins and Cline.

Regarding Mr. Watkins' adjustment for transportation revenues, it certainly appears that UGI Gas is currently recovering the $1.988 million in "margin," almost entirely from Rate DS customers, in the form of pooling and system access charges. Unless these margins are currently being credited to the PGC, I agree with Mr. Watkins that these values should be included in the Rate DS present-rates revenues. This would serve to reduce the overall rate increase required in this proceeding. Because the Company proposes to eliminate these revenues from the proposed DS and LFD rates, I further agree with Mr. Watkins that they should not be reflected in proposed rate revenues.[7]

Q. What impact does your acceptance of the interruptible and transportation revenue adjustments proposed by Mr. Watkins have on your revenue allocation recommendations?

A. I updated my cost allocation analysis from Exhibit IEc-3 to reflect the higher current-rates revenues proposed.[8] In so doing, I relied on Mr. Watkins' adjustments. Exhibit IEc-R1 provides a summary of that analysis, and the detailed working file will be circulated with this testimony. I then applied the same revenue allocation methodology that I used in my direct testimony. For the Rate R/RT class, I again applied a 1.5 times system average factor, but I relied on the higher current-rate revenues values discussed herein. Thus, while I use the same rate increase constraint as Mr. Watkins, I recommend a lower increase for the R/RT class. Because revenues from the interruptible class exceed allocated costs by a significant amount, I assign no increase to this class under this adjusted scenario.

A summary of the revenue allocation recommendations is shown in Table IEc-R1 below.

[7] Similar adjustments may be warranted for any portion of the Rate N/NT minimum bill charges that are not credited to the PGC, as shown in the Company's revenue adjustment at Exhibit DEL-3(I). At this time, however, I do not have sufficient information to evaluate this issue.

[8] Issues related to Mr. Cline's recommended adjustments to current-rates revenues from Rate R/RT and N/NT volumes is discussed below.

Table IEc-R1 Revenue Allocation Comparison $mm				
	UGI Gas	Exhibit IEc-3	OCA Direct	Exhibit IEc-R1
R/RT	$43.33	$44.18	$31.78	$29.53
N/NT	$12.50	$ 7.27	$ 8.49	$ 7.53
DS	$ 0.98	$ 1.43	$ 0.67	$ 1.45
LFD	$ 1.75	$ 3.79	$ 1.19	$ 3.62
XD	--	--	--	--
IS	--	$ 1.90	--	--
System	***$58.56***	***$58.56***	***$42.12***	***$42.12***
Note: I&E revenue allocation recommendations with proposed revenue reduction are discussed below. Sources: UGI Exhibit D, Exhibit IEc-3, OCA Statement No. 3 Table 8, Exhibit IEc-R1.				

Q. Please explain why your revenue allocation in Exhibit IEc-R1 actually allocates more revenue to the N/NT than your initial proposal in Exhibit IEc-3, despite the significant reduction in the revenue requirement.

A. While this result is neither intuitive nor obviously equitable, it is simply the arithmetic results of the applying the same revenue allocation methodology that I employed in my direct testimony. Essentially what happens is that taking some $17 million out of the overall revenue requirement reduces the overall system average percentage increase. Because the R/RT class increase is constrained to be no more than 1.5 times system average, the reduction in the overall system increase substantially benefits the R/RT class. In addition, the fact that the R/RT class represents a significant share of current base rate revenues also contributes to this effect, as does the loss of the ability to pass on any of the increase to the interruptible class.

Q. Can you explain generally why you assign higher rate increases to the DS and LFD class than those proposed by the Company and Mr. Watkins?

A. Yes. The changes that I made to the Company's cost allocation methodology in the areas of design day demand allocation factors and meters costs generally served to increase costs assigned to the DS and LFD classes and reduce costs assigned to the R/RT and

N/NT classes. Mr. Watkins' cost allocation analysis does not include those changes. Thus, my higher relative revenue assignment for DS and LFD classes reflects the higher relative costs in my cost allocation analysis.

Q. Please comment on Mr. Cline's recommendations for revenue allocation in the event that a significant base rate revenue increase is awarded by the Commission.

A. Rather than the Company's proposed overall increase of $58.6 million, I&E recommends that an overall rate decrease of $18.6 million be applied in this matter. A significant factor contributing to that difference is Mr. Cline's assessment of current-rate revenues, in which he concludes that the Company understates current-rate revenues by some $48.5 million. Of that amount, $15.5 million is related to the understatement of interruptible revenues discussed above. The remainder relates to Mr. Cline's conclusion that the Company's forecast of test year residential class throughput should be increased by 12 percent and the Company's forecast of test year Rate N/NT throughput should be increased by 30 percent.

Mr. Cline proposes that the $18.6 million rate reduction be linearly apportioned among all classes not subject to negotiated rates, namely the R/RT, N/NT, DS and LFD classes, based on current-rate revenue. In so doing, Mr. Cline implicitly ignores the results of the Company's cost allocation analysis, as well as the implications of the significant volume adjustments that he proposes. Moreover, because Mr. Cline includes gas supply revenues in his allocation method, he effectively assigns the largest rate decrease to the R/RT class, despite the fact that all cost allocation studies in this proceeding show this class to exhibit class rates of return well below system average. A summary of Mr. Cline's revenue allocation is included in Table IEc-R2 below.

To estimate the cost allocation impact of Mr. Cline's volume adjustments, I modified my cost allocation study from Exhibit IEc-3 to reflect Mr. Cline's proposed changes to current rate revenues, as well as the implicit changes to the volumetric allocation factors (with proportionate adjustments to the demand allocation factors). I also adjusted the allowed return and income tax assumptions downward such that the overall revenue requirement matches the I&E recommendation. A summary of the results of that analysis is shown in Exhibit IEc-R2, and the corresponding electronic workpapers will be distributed with this testimony.

As shown in Exhibit IEc-R2, the I&E adjustments produce a cost allocation study in which the R/RT class continues to exhibit a rate of return well below system average, while the other non-flex rate classes exhibit rates of return well above system average at current rates. Of particular importance is that the Rate N/NT class, under Mr. Cline's assumptions, exhibits the highest class rate of return at current rates of the non-flex-rate classes. This significant increase in the rate of return for the N/NT class is caused by the large increase in volumes and current-rate revenues calculated by Mr. Cline for that class, with no corresponding increases in customer-related costs such as meters and services plant. These effects cause the unit costs for the N/NT class to drop sharply relative to the Company's cost allocation study, resulting in a much higher class rate of return. It is also important to recognize that, even with the volumetric adjustments recommended by Mr. Cline, the R/RT class rate of return continues to fall well below system average.

Q. If the Commission adopts I&E's recommendations regarding a significant rate decrease, how should the rate decrease be allocated?

A. As I noted earlier, this question would be much better answered by first resolving the large revenue requirement and methodological issues, and then evaluating revenue allocation and rate design. However, as that approach is unlikely, I rely on the cost allocation analysis in Exhibit IEc-R2 to respond to this question. In that context, and consistent with my direct testimony, I recommend that the rate decrease be applied to the non-flex-rate classes which are providing the cross-subsidies, namely the N/NT, DS and LFD classes. Based on the analysis in Exhibit IEc-R2, the revenue allocation shown in Table IEc-R2 below would result in a reduction of about one-third in the cross-subsidies from those classes.

Table IEc-R2 Revenue Allocation for I&E Proposed Revenue Requirement $mm					
	Present Dist'n Rate Revenue	I&E Proposed Increase		RDK Proposed Increase	
		$mm	%	$mm	%
R/RT	$117.26	($10.49)	-8.9%		
N/NT	$ 79.52	($ 6.15)	-7.7%	($ 13.70)	-17.2%
DS	$ 10.60	($ 0.70)	-6.6%	($ 1.43)	-13.5%
LFD	$ 25.01	($ 1.30)	-5.2%	($ 3.51)	-14.0%
XD	$ 11.76				
IS	$ 20.38				
System	$264.55	($18.64)	-7.0%	($18.64)	-7.0%
Source: Exhibit IEc-R2; I&E Exhibit No. 5, Schedule 10					

Q. Mr. Watkins also proposes a revenue allocation methodology in the event of an overall reduction in the allowed rates. Is his proposal reasonable?

A. It is not. Mr. Watkins would assign a modest share of the rate decrease to the Rate R/T class. However, there is no cost allocation evidence from any party to this proceeding, including Mr. Watkins, that would suggest that current rate revenues from the R/RT rate classes would produce a class rate of return anywhere near system average, even at a substantially reduced revenue requirement. For example, Mr. Watkins' cost allocation study reports that the R/RT class exhibits a rate of return at present rates of 1.99 percent, compared to a system average return of 5.56 percent. While there are certainly reasons to avoid assigning an excessive rate increase to the Rate R/RT class if the Company's proposed increase is adopted, there are no comparable reasons to require that the Rate R/RT class share in any rate reduction.

In the event that it does conclude that an overall rate reduction is merited, the Commission should take note of the fact that it has been more than 20 years since the Company's last base rates proceeding, and non-residential customers have almost certainly been providing significant subsidies to the residential class throughout that period, even using Mr. Watkins' cost allocation analysis. In that light, it would be grossly inequitable to arbitrarily continue the excessive subsidization of the Rate R/RT classes, by requiring that the R/RT class share in a rate reduction that is not justified by any cost analysis on record.

Because every cost allocation study filed in this proceeding shows a substantial cross-subsidization of the Rate R/RT class by the non-residential classes, any overall rate reduction should be shared among the classes providing the subsidy. Since the negotiated rate classes XD and IS have rates that are at least theoretically set by market conditions, an overall rate decrease should be shared between the N/NT, DS and LFD classes.

4. Rate Design

Q. Please summarize Mr. Cline's recommendations regarding rate design for the N/NT classes.

A. Mr. Cline offers two alternative recommendations. At the Company's proposed rate increase for the class, Mr. Cline recommends that the customer charge be set at $14.00 per month, and that the Company's current declining block tariff structure for commodity charges be retained, but limited to a two tiered declining block tariff. If a rate decrease is assigned, Mr. Cline recommends that the customer charge also be set at $14.00 per month, and that a two-tier declining block commodity tariff be retained, albeit with lower charge levels. A comparison of Mr. Cline's proposals with those offered by the Company and those in my direct testimony are shown in Table IEc-R3 below.

Table IEc-R3 Rate N/NT Distribution Rate Design					
	Current Rates	UGI Gas Proposed	RDK Direct Testimony	I&E @ UGI Increase	I&E @ Rate Reduction
Dist'n Rate Increase $mm	--	$12.50	$7.27	$12.50	($6.15)
Customer Charge ($/mo)	$8.55	$32.00	$20.00	$14.00	$14.00
First 25 Mcf ($/mcf)	4.0268	3.6932	3.6696	4.3720	3.2329
Next 475 Mcf ($/mcf)	3.5309				
>500 Mcf Winter ($/mcf)	2.4374			3.40000	2.9000
>500 Mcf Summer ($/mcf)	2.2902				
MFC (% of PGC)	0.36%	0.47%	0.47%	0.47%	0.47%
GPC ($/mcf)	0.0400	0.01460	0.1003	0.0146	0.0146
EE&C ($/mcf)	--	0.02784	0.0381	0.0278	0.0278*

* Mr. Cline retains the EE&C charge in the proposed tariff under the reduction scenario, although I&E witness Ms. Gumby recommends that the EE&C plan be rejected in the rate reduction scenario. It is likely that Mr. Cline intends that the EE&C charge be rolled into the volumetric charges in this scenario.

Sources: UGI Exhibit E, Exhibit IEc-3, Cline workpapers, UGI-I&E-III-12.

Mr. Cline's proposed changes to the Company's tariff design are based entirely on the principle of rate gradualism, and are designed to reduce the relative magnitude of intra-class rate increases and rate decreases inherent in the Company's proposal.

Q. Are Mr. Cline's proposals unreasonable?

A. No they are not. The primary difference between Mr. Cline's proposals and my own is that Mr. Cline relies more heavily on the principle of rate gradualism. While Mr. Cline's approach retains more complexity than that proposed by the Company or in my direct testimony, it has the advantage of reducing differences in intra-class rate increases. It also has the less obvious advantage of potentially reducing discontinuities between rates for larger customers in Rate N/NT and smaller customers in Rate DS. As such, to the extent that the Commission is concerned about intra-class rate shifts in Rates N/NT, Mr. Cline's rate design proposal would be a reasonable approach.

5. <u>NGS Issues</u>

Q. In his direct testimony, Mr. Magnani raises issues involving balancing rules, allocation of the Company's Transco capacity, OFO penalties, and pool balancing requirements. Mr. Crist also raises the issue of the release of storage capacity to Choice NGSs. Are these issues properly raised in a base rates case?

A. I am advised by OSBA counsel that these issues are properly addressed in the Company's annual Section 1307(f) proceedings, where matters involving costs to provide utility supplier-of-last-resort ("SOLR") gas sales are adjudicated.

Q. If the Commission determines that the allocation of upstream gas transmission capacity is properly addressed in this proceeding, do you agree with Mr. Magnani's proposal that UGI Gas allocate some of its upstream Transco capacity to non-Choice NGSs?

A. No. Mr. Magnani appears to conclude that the fact that UGI Gas has contracted for pipeline capacity that provides access to relatively low-priced gas on behalf of its PGC customers is somehow unfair to NGSs who serve regular transportation customers. Based on my experience, this belief represents a misunderstanding of the basic nature of transportation service in Pennsylvania. In this jurisdiction, larger transportation customers or their suppliers are required to procure their own upstream transportation and load balancing services, or purchase those services ala carte from utility tariffed rates.[9] In contrast, UGI Gas purchases the upstream capacity necessary to meet its supplier of last resort ("SOLR") obligations for its purchased gas cost ("PGC") customers, and the PGC customers generally absorb the risk associated with those purchases.

For the most part, this approach provides significant flexibility to transportation customers, who have no obligation to assume cost responsibility for the upstream capacity purchased by the utility. This ability to independently procure upstream capacity also tends to result in lower per-mcf costs for larger, high load factor customers,

[9] Mr. Magnani indicates that UGI Gas will assign Transco capacity to "Choice" suppliers under its policies for retail competition. Because retail Choice service is generally structured to allow customers to shift flexibly from utility sales service under Rates R and N to Choice service under Rates RT and NT, it is not unreasonable for the Company to provide for shifts in upstream capacity, so as to avoid having both too much and too little capacity.

who would otherwise likely bear a disproportionate share of load balancing costs.[10] There is simply no reason why PGC customers, who absorb all the risk associated with capacity procurements, should be required to share the value of one particular contract simply because it offers relatively lower costs.

Moreover, I very much doubt that Mr. Magnani would support the logical end result of his recommendation, namely that all Pennsylvania NGDCs be required to assign a portion of all of their upstream capacity to NGSs, regardless of how costly that capacity may be. It would therefore appear that Mr. Magnani proposes to cherry-pick the PGC capacity that NGSs desire, and subject only that capacity to a mandatory assignment to NGSs. As such, Mr. Magnani's offering appears to be something less than an equitable proposal.

Q. Both Mr. Magnani and Mr. Crist conclude that the Company has incorrectly excluded working capital costs in the derivation of its gas procurement charge ("GPC"). Do you agree?

A. The GPC is designed to recover costs incurred by the Company related to providing gas supply service to non-shopping (aka "PGC") customers. The Commission's regulations explicitly recognize working capital requirements as one such cost component for the GPC, and there is no question that UGI Gas incurs both gas in storage and cash working capital costs related to its provision of gas supply to non-shopping customers.[11] However, the Company also provides certain services to retail "Choice" shopping customers that involve the use of both gas in storage and cash working capital. Thus, one approach for recovering these costs would be to develop separate GPC charges for PGC and Choice customers, reflecting the difference in working capital costs associated with the two different types of customers. However, if the Company provides identical services associated with working capital to both sales and Choice customers (which appears to be the Company's position), there is no need to include those costs in the GPC.

---

[10] In general, Pennsylvania NGDCs allocate PGC capacity costs on a volumetric basis, which serves to over-assign load balancing costs to high load factor customers who require little in the way of load balancing capacity.

[11] 52 Pa. Code § 62.223 (b)(i).

And finally, if the Company incurs higher working capital costs to serve PGC customers than it does to serve Choice customers, a reasonable approach would be to include the *excess* cost amount in the GPC, while implicitly recovering an equal amount from PGC and Choice customers in base rates. It is this last approach that I advocate in my direct testimony.

As I indicated in my testimony, the Company has not provided any analysis of the relative working capital costs of serving PGC versus serving Choice customers. However, neither Mr. Magnani nor Mr. Crist acknowledges that the Company does provide some services to Choice customers that involve the use of working capital, and neither witness has prepared a detailed assessment of the difference (if any) in cost to provide these services to Choice customers and to PGC sales customers.[12] As such, there still remains no reasonable basis for determining the magnitude of working capital costs that should reasonably be included in the GPC.

Also, as a matter of clarification, neither witness appears to recognize that the GPC only directly affects competition between PGC and retail Choice competition between the R and RT classes, and between the N and NT classes. For competition in those classes, the difference in rates between PGC service and Choice service is simply the PGC charge plus the GPC.

However, for customers interested in taking service under the Rate DS, LFD and XD classes, the competitive calculation is very different. For example, a customer who switches from Rate N sales service to Rate DS transportation service avoids both the PGC charge and the GPC, but also pays the (generally lower) Rate DS gas distribution tariff rates. For this competitive comparison, the issue of whether working capital costs are or are not included in the GPC has no impact on competition. UGI Gas allocates these working capital costs only to Rates R/RT and N/NT. Thus, these costs are not charged to transportation customers, regardless of whether they are included in base rates

[12] It appears that Mr. Crist includes return on 100 percent of gas storage inventory at the Company's proposed weighted average cost of capital (8.17 percent). He does not include associated income tax costs in his cost calculation, nor does he include CWC related to gas supply. Mr. Magnani does not provide any calculations at all regarding the GPC, but does comment that cash working capital should be included in the cost basis.

or in the GPC. A customer who switches from, say, Rate N to Rate DS transportation service will avoid the gas supply working capital costs, whether those are included in the Rate N base rates charge or if they are included in the GPC. Thus, the primary competitive impact of including working capital costs in the GPC is between retail sales and retail Choice service.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R2

CONFIDENTIAL

OSBA Statement No. 3
6/2/16 [illegible]

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2015-2518438
UGI UTILITIES, INC. (Gas Division)	:	

Surrebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: May 25, 2016

Date Submitted for the Record: ______________________

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct and rebuttal testimony, with associated exhibits, earlier in the proceeding and my qualifications were presented therein.

Q. What issues do you address in this rebuttal testimony?

A. At the request of OSBA, this rebuttal testimony addresses various aspects of the rebuttal testimony submitted by the following witnesses:

- UGI Gas Utilities, Inc. Gas Division ("UGI Gas" or "the Company") witness Mr. Paul J. Szykman, regarding forecast test year current rates interruptible revenues;
- Company witness Mr. Paul R. Herbert, regarding cost allocation issues;
- Company witness Mr. David E. Lahoff, regarding cost allocation, revenue allocation and rate design issues;
- Company witness Mr. Robert R. Stoyko, regarding current rates interruptible revenues and various rate design issues;
- Company witness Ms. Angelina M. Borelli, regarding the development of design day demand allocation factors;
- Company witness Mr. Theodore M. Love, on matters relating to the Company's proposed EE&C plan;
- Mr. Glenn A. Watkins, representing the Pennsylvania Office of Consumer Advocate ("OCA") on matters of cost allocation.

Q. Do you have any introductory comments?

A. I do. While I disagree with some of the rebuttal testimony presented by the various witnesses, I note that a number of these witnesses expressed agreement with the positions that I adopted in my direct testimony, including the following:

- In the cost allocation analysis, Mr. Herbert partially corrects the inconsistency in the allocation of gas supply working capital costs, he partially corrects the errors in the allocation of meters costs, and he partially corrects errors in the Company's design day allocation factors.
- The Company agrees to include some gas supply related cash working capital costs in its gas procurement charge.
- The Company accepts my recommendation that EE&C costs for non-residential customers should be further segregated into rate class groups, to better keep EE&C cross-subsidization *within* rate classes rather than *between* rate classes.
- While retaining her view that the proposed EE&C Plan should be rejected in its entirety, I&E witness Ms. Lisa A. Gumby agrees that my proposed modifications to the EE&C plan for non-residential customers should be adopted if the Commission agrees that an EE&C plan should be permitted.
- Mr. Watkins agrees with my direct testimony that the Company's proposed design day demand allocation factors are seriously flawed as a result of a significant mismatch between loads and demands, which result in an inappropriate over-assignment of costs to smaller customers.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 addresses the issue of interruptible service revenues, in the testimony of Mr. Szykman and Mr. Stoyko;
- Section 3 reviews the cost allocation issues raised by Mr. Herbert, Mr. Lahoff, Ms. Borelli, and Mr. Watkins;

- Section 4 addresses revenue allocation issue, in the testimony of Mr. Lahoff;
- Section 5 addresses rate design issues for the Rate N/NT classes and the proposed TED Rider in the testimony of Messrs. Lahoff and Stoyko;
- Section 6 addresses issues involving the EE&C plans, in the testimony of Mr. Love.

2. Interruptible Service Revenues

Q. Mr. Szykman indicates that gas distribution companies are unlike other regulated utilities in that customers face competitive alternatives. Does this issue justify the Company's proposed future test year "current-rates" revenue of $4.9 million from interruptible service?

A. No, it does not. Mr. Szykman is correct that gas customers often have competitive alternatives. Mr. Syzkman is also correct that the Commission has allowed natural gas distribution companies ("NGDCs") to offer negotiated rates rather than fixed tariff rates to certain types of customers, particularly those with alternative fuel of system bypass options. However, where such rates are set below the allocated cost of service, it is generally incumbent upon the utility to demonstrate (a) that the customer would switch to an alternative fuel or bypass the distribution system if the negotiated rate were not established, and (b) that other ratepayers are better off by retaining the customer at the discounted rate than by losing the customer.

However, with respect to forecast test year revenues in this proceeding, the Company has not made any such demonstration. The Company does not propose to set interruptible rates at the rate necessary to deter fuel switching – it proposes to set rates based on a hybrid cost allocation calculation. As I indicated in my rebuttal testimony, current rates revenue should be set based on current rates revenue, not based on allocated costs. If the Company faces a significant and credible fuel price threat such that it will need to slash its interruptible rates in 2017 by 75 percent relative to 2015, it should provide that information to the parties and to the Commission. In contrast, the only customer-specific information that the Company presented in response to discovery indicated that current-rates interruptible revenues for 2017 would be approximately $20 million, consistent with past performance.

Thus, the problem in this proceeding is not that the intervenor parties did not consider and recognize the impact of competition on the negotiated rate revenues for interruptible customers. It is that the Company has failed to provide any market-based assessment of what those revenues are likely to be, given current expectation for market conditions.

As the Company has offered no reasonable assessment of current rates interruptible service revenue for the forecast test year, I conclude that the reliance of the OCA and I&E witnesses on the historical record is reasonable.

Q. At page 23 Mr. Szykman indicates that, under the Company's proposed interruptible rate revenues, the Company is at risk for any revenues below $4.9 million, and can use any excess revenues above $4.9 million to invest in capital projects and defer future rate cases. Is this accurate?

A. Only loosely. Under test year rate regulation, unless revenue decoupling mechanisms are in place, the Company is at risk for revenues from all rate classes, both firm service and interruptible customers. That this risk exists is not a reason to forecast test year interruptible revenues at 75 percent below the Company's own budget projections. Moreover, while it is technically true that UGI Gas would be at risk for revenues below $4.9 million under its proposal, this risk would seem to be minimal given that the Company's interruptible revenues have at or above $19 million for more than a decade. Also, while UGI Gas could potentially use revenues from interruptible customers to invest in new equipment, it could also legitimately simply give the extra earnings to its shareholders or use it to invest in its non-regulated businesses. I very much doubt that Mr. Szykman is offering to use excess revenues above $4.9 million to invest in utility plant and equipment that the Company does not intend to claim as rate base in future rates proceedings. Finally, Mr. Szykman's claim that this approach will allow the Company to defer future rate cases conflicts with the basic principles of test year regulation. In effect, Mr. Szykman is saying to the Commission that if you let us earn a rate of return in excess of the cost of capital, we will not bother you with more frequent rate cases. In my view, adopting Mr. Szykman's position would be an abdication of the regulatory responsibility to set test year rates that provide the utility with a reasonable opportunity to recover forecast test year costs, no more and no less.

Q. At page 26, Mr. Szykman argues that if interruptible rate revenues are set at historical averages, the Company will have no incentive to try to maximize revenues from these customers and will simply file for base rate increases with every drop in interruptible revenues. Does that make any sense?

A. No. As I indicated earlier, under test year rate regulation, the Company is at risk for all revenues once rates are set. Whether interruptible current rate revenues are set at $4.9 million or $20 million, the Company gets to keep every additional dollar that it can negotiate from interruptible customers. Moreover, if the Commission allows UGI Gas to use $4.9 million as current rate interruptible revenues in this proceeding, it is likely that the Company will quite sensibly conclude that the Commission will do so again in the next proceeding. As such, setting a lower interruptible level in this proceeding will provide no incentive at all for the Company to defer future rate filings.

Q. At pages 26 and 27, Mr. Szykman criticizes Mr. Watkins' cost allocation methodology as inappropriate for interruptible revenue allocation and rate design. Would your cost allocation method be a reasonable approach for setting cost-based interruptible rates?

A. I do not believe that it would. As I indicate at some length in my direct testimony, *allocating costs to interruptible customers is a less than precise exercise, even by the* standards of cost allocation methods. As all parties to this proceeding appear to agree that interruptible rates should be set based on negotiation, the impact of alternative cost allocation methods for interruptible is effectively nil. The only real issue is: how much revenue can UGI Gas reasonable earn from interruptible customers in the future test year, given market conditions.

Q. At page 29, Mr. Szykman presents a graph showing that crude oil prices have been dropping since mid-2014, and on page 30 he cites prices from February 2015 that spot market prices for natural gas exceeded those for fuel oil. Are these arguments

credible justifications for assuming that revenues from interruptible rate customers will fall by roughly 75 percent between FY 2015 and FY 2017?

A. No. Mr. Szykman's analysis is anecdotal and out of date. In Exhibit IEc-S1 Schedule 1 attached to this testimony, I present a comparison of spot heating oil prices (NY Harbor) and natural gas wellhead prices (Henry Hub) on a monthly basis since 2005, as well as the heating oil price premium over that period. I then compare that price premium to UGI Gas's interruptible revenues. As shown, the actual pattern of UGI Gas' interruptible revenues shows very little correlation with the oil price premium.

For example, in 2005 and 2006, the oil price premium was quite low, in the $3 to $5 per mmbtu range, and yet UGI Gas was able to earn nearly $20 million per year from interruptible rate customers. As the fuel oil premium rose in the latter part of the '00s, UGI was able to modestly increase revenues for a couple of years. However, since about 2008,and despite a huge run-up in the relative price of fuel oil, UGI Gas's interruptible revenues have been drifting downward. Absent a detailed review of the specifics of individual customers, one would reasonably conclude that UGI Gas was not, in fact, trying to maximize revenues from these customers, but was in fact pricing delivered gas well below the cost of the alternative fuel. Based on the figures, it appears that UGI Gas was much more focused on increasing interruptible customer volume than it was on keeping rates in line with the price of alternative fuels.

Beginning in early 2014, fuel oil prices began dropping sharply, bottoming out in January 2016. However, despite that drop, UGI Gas interruptible revenues remained in the $20 million range for FY2015. This pattern also suggests that UGI Gas had not been trying to maximize revenues from interruptible customers over the past seven or eight years, but in fact had significant room in their rates to absorb a substantial loss in the natural gas competitive price advantage.

And, finally, since the beginning of this year, fuel oil prices have firmed considerably. Futures prices for FY2017 indicate that the fuel oil price premium over natural gas will be modestly below the average for 2015, and well above the values in FY2005, FY2006, FY2007, and FY2009. Since UGI Gas was able to earn more than $20 million in interruptible revenues in all of those years, it is not unreasonable to conclude that it can and should be able to do so in FY2017.

Q. In his testimony, Mr. Stoyko indicates that "it strains credulity" to believe that UGI Gas does not maximize revenues from interruptible service customers. Can you respond?

A. Normally, I would agree. However, the evidence of Exhibit IEc-S1 Schedule 1 is clear that the Company failed to increase rates to Interruptible Service customers during the 2008 to 2014 period despite enormous increases in its competitive price advantage.

Q. At page 48, Mr. Stoyko indicates that you could have investigated the competitive alternatives available to each interruptible customer in the discovery process. Is that reasonable?

A. No. The OSBA did request that information in OSBA-I-15, which included a request that the Company provide the basis for the interruptible rate. The Company's response to that interrogatory referenced OCA-IV-22 for interruptible rate customers. The response to OCA-IV-22 provided no information regarding the basis for the negotiated rate, and it indicated that the budgeted revenue for forecast future test year 2017 was $18.76 million, which appears to exclude the revenues from the large interruptible customer. Thus, based on the Company's incomplete response to the OSBA's request in this area, one must reasonably conclude that the negotiated rate forecast revenues for interruptible service in the test year should be on the order of $20 million.

Q. At pages 30 to 32, Mr. Szykman puts forward an option for a sharing mechanism for interruptible revenues. Is this a reasonable proposal?

A. I am advised by OSBA counsel that this alternative should properly have been submitted in direct testimony, and that putting forward such a proposal in rebuttal is improper.

To the extent the Commission does not exclude this proposal as improper, my assessment of the proposal is as follows. I agree with Mr. Szykman that the Company faces some revenue risk associated with the impact alternative fuel price fluctuations on its interruptible revenues, despite the limited historical evidence. Had the Company offered such a proposal in its direct testimony, I would have been willing to consider and offer a more reasonable alternative to the proposal if it had been offered in direct testimony with sufficient opportunity for discovery and analysis. As it is, however, the proposal is not reasonable, as it cannot be fully evaluated.

As to the specifics of the mechanism, Mr. Szykman proposes to share all interruptible revenues variations above and below a base level revenue amount of zero dollars at a 50/50 rate between ratepayers and shareholders. Thus, if a reasonable forecast for interruptible revenues (based on historical actual levels) is $20 million, UGI Gas gets to keep $10 million (above and beyond its allowed return on capital), and UGI Gas ratepayers get to pay the extra $10 million above the reasonable cost of gas. Needless to say, this proposal is hardly equitable.

It is certainly possible that the proposal could be made substantially more reasonable by sharing revenue variations above and below a reasonable forecast of interruptible levels. Thus, for example, if a reasonable forecast of interruptible revenues is $20 million, and actual interruptible revenues are $25 million, the Company would be permitted to keep $2.5 million and $2.5 million would be credited back to ratepayers in some manner.

Unfortunately, even so modified, there are a number of questions that cannot be answered due to the late date for this proposal. If the proposal is modified to include a base revenue level of, say, $20 million, there are questions as to whether that base value should be modified based on actual results going forward. Also, there are questions as to whether the credits and charges in such a mechanism should apply to Rate XD-Firm customers, as proposed by Mr. Szykman. Since those customers are subject to negotiated rates, it is unclear why these customers should participate in any credit sharing (and they doubtless would object to participating in the cost sharing that would be necessary for a balanced mechanism). Finally, Mr. Szykman proposes to apply the credits to customer charges. While this approach might be reasonable for the relatively homogeneous residential class, it is not reasonable for Rate N/NT and DS customers. A charge/credit mechanism that applies only to the customer charge implicitly assigns a very significant share of the risk/reward in the mechanism to smaller customers within each of those classes. This approach is wholly inconsistent with the Company's own cost and revenue allocation methods, and therefore should not be adopted without a more careful and thorough review.

3. Cost Allocation

Q. At pages 3 to 4 of his rebuttal testimony, Mr. Herbert defends his proposed method for cost allocation to interruptible customers based on the argument that the Company would still need its entire distribution system even if interruptible customers did not take service. Please comment.

A. My initial observation involves what Mr. Herbert did not say. Mr. Herbert indicated that the cost of service study should be a reasonable guide in constructing rate design for customer groups. He did not say that the cost of service study should be used to set the future test year revenue level for interruptible customers, as the Company proposes in this proceeding.

Second, I would agree with Mr. Herbert that there are likely to be some interruptible customers who rely only on distribution assets that would otherwise go unused, and that those customers are not causally responsible for distribution costs. However, it is also likely that there are interruptible customers who represent a significant share of the peak day usage of some portions of the distribution system, and are therefore causally responsible for some component of distribution costs.

Unfortunately, absent a detailed assessment of the specific mains used by interruptible customers, which the Company opted not to undertake, it is not possible to tell which situation is more common or which is more representative of system conditions.

As I indicated above, if the Commission determines that rates for interruptible customers are negotiated "flex" rates based on the price of alternative fuels, and that test year revenues reflect a reasonable forecast for such revenues, the cost allocation methodology for interruptible customers is essentially irrelevant. It is only when UGI Gas proposes to forecast its test year revenues based on a highly uncertain hybrid allocated cost study that cost allocation for interruptible service becomes relevant.

To the extent that UGI Gas wishes to adopt cost-based rates for interruptible customers, I recommend that it develop a direct assignment cost allocation method for each interruptible customer. Where particular mains serving the interruptible customer would be constrained without the ability to fully interrupt the customer, the customer should be assigned no cost for that main. Where mains serving interruptible customers have excess capacity beyond firm plus interruptible requirements, the interruptible customer should be assigned its share of the costs.

In the absence of such analysis in the context of this proceeding, the most reasonable course is to continue to allow UGI Gas to negotiate rates with interruptible customers, and to establish the class revenue requirement based on a reasonable forecast for those revenues.

Q. At pages 18 to 19, Mr. Herbert defends his segregation of mains costs between small and large mains for Rate LFD customers on the basis that the direct assignment method for Rate XD customers which relied on hydraulic modeling showed that Rate XD customers generally used only a small percentage of the small mains on the system. Is this reasonable?

A. Mr. Herbert makes the general point that there are economies of scale in natural gas distribution systems, such that larger customers are less costly to serve than smaller customers, per unit of peak demand, because larger customers use proportionally less of the small mains system. While Mr. Herbert's logic is likely to be directionally correct, this analogy is insufficient to justify his proposed methodology. Yes, it is likely that larger customers are likely to be proportionately larger users of higher pressure and larger diameter mains than they are of smaller low-pressure mains. Nevertheless, it is also likely that *some* smaller customers in every rate class are not served by small diameter mains. Thus, if the cost allocation method does segregate mains by size, Mr. Herbert must, at a minimum, adjust all allocation factors to reflect each class' relative use of small and large mains. Second, the costs for the large mains that are used *only* by larger customers should be assigned only to the large customer classes. While this approach still falls far short of the accuracy of a direct assignment method, it would be far superior to Mr. Herbert's approach. Moreover, without this analysis, it is unreasonable to separately allocate small and large diameter mains.

In his rebuttal testimony, Mr. Herbert relies on the fact that small mains represent only 6.7 percent of the mains costs assigned to Rate XD customers, based on the hydraulic modeling analysis. He argues that Rate XD customers are, on average, 20 times larger than Rate LFD customers, while LFD customers are 480 times larger than residential and 85 times larger than average Rate N/NT customers, and therefore the Rate LFD use of small mains should be closer to that of Rate XD than that of Rates R/RT and N/NT.

However, even if one were to assume that the relative usage of small mains is inversely proportional to average customer size, as Mr. Herbert suggests, Mr. Herbert's own allocation methodology fails to recognize this relationship. Mr. Herbert treats all customers in the R/RT, N/NT and DS classes the same, regardless of the fact that Rate DS customers are, on average, some 84 times larger than the average residential customer (and LFD customers are, on average, less than 6 times larger than Rate DS customers). Thus, under Mr. Herbert's logic, Rate DS customers should be assigned a considerably lower share of small mains costs than Rate R/RT customers. Similarly, under Mr. Herbert's logic, Rate N/NT customers should be assigned a modestly lower share of small mains costs than Rate R/RT customers. Instead, contrary to his hypothesis about customer size, Mr. Herbert proposes to treat all R/RT, N/NT and DS customers the same. Mr. Herbert's cost allocation proposal is shown in Table IEc-S1 below.

Table IEc-S1 Small Mains Share of Allocated Mains Cost UGI Gas Proposed Method			
	Small Mains Share of Mains Cost	Average Annual Per-Customer Throughput	Indexed Throughput (R/RT = 1.0)
R/RT	42.3%	65	1.0
N/NT	42.3%	368	5.6
DS	43.0%	5,472	83.8
LFD	13.8%	31,389	480.4
XD	6.7%	645,131	9,874.3
Interruptible	33.2%	137,744	2,389.8
Total	**38.7%**	**315**	**4.8**
Source: Exhibit IEc-S1 Schedule 2			

In effect, Mr. Herbert has concocted a methodology which reduces costs assigned to the largest customers based on hypothesized scale economies, but then declines to apply those scale economies to small and medium-sized business customers.

The basic problem for mains cost allocation in Pennsylvania is that the Commission relies on a cost allocation method that fails to reasonably reflect the fact that mains costs are related to both size and length of main, and that there are likely to be some economies of scale for serving larger customers. Utility cost allocation practitioners such as Mr. Herbert are then forced to adopt alternative methods, such as splitting the mains costs into small and large size mains or direct assignment of mains costs to certain customers, in order to reduce costs that are assigned to larger customers. While this approach is not wholly unreasonable, it needs to be done with some care. As detailed in my direct testimony and reviewed again above, the Company has not undertaken even the most basic analysis necessary to adopt such a methodology. Without such analysis, it is unreasonable to segregate mains into small and large diameter categories, and Mr. Herbert's rebuttal does not justify the absence of this analysis.

Q. At page 20, Mr. Herbert indicates that your proposed modification to the meters cost allocator "ignores the fact that the LFD and XD classes are allocated a substantial investment per customer in Account 385 . . ." Is he correct?

A. No. As shown in Table IEc-2 and detailed in Exhibit IEc-3 in my direct testimony, and in the electronic workpapers provided to the Company, the analysis supporting my meters cost allocation factors included meters costs in all accounts 381 to 385. Mr. Herbert's criticism is simply wrong.

Q. Mr. Herbert also makes a modification to the meters cost allocator for Rate N/NT. Is this an adequate response to your direct testimony?

A. While I acknowledge that Mr. Herbert has adopted a part of my recommendation in this respect, his rebuttal testimony does not address the significant anomalies and inconsistencies in the Company's allocation method for all meters costs, as detailed in my direct testimony.[1] As such, I retain my conclusion that the Company's method is not reasonable, and that a better and more detailed assessment of meters costs should be undertaken.

Q. Turning to the issue of the allocation of working capital costs related to gas supply, Mr. Herbert indicates that both cash working capital ("CWC") and gas storage inventory costs are incurred for both sales and Choice customers, and that he modified the allocation factor for gas storage inventory costs. At pages 63-64, Mr. Lahoff makes a similar argument regarding inventory costs. Mr. Lahoff goes on to accept your recommendation to include some CWC costs in the gas procurement charge. Does that address the concern in your direct testimony?

A. Not completely. I acknowledged in my direct testimony that it was likely that the Company incurred both of these types of working capital costs for both sales and Choice customers, but that the Company failed to make any demonstration that the costs were equivalent on a per-mcf basis. Specifically, the Company should answer the questions: Does the Company incur the same magnitude of costs, per mcf delivered, in providing

[1] These flaws and anomalies include the apparent failure to reflect customer migration, the unusually low cost used for residential meters, the allocation of meters costs among some non-residential classes based on customer count rather than recognizing the higher cost for larger meters, and the large differences in relative meters cost at UGI Gas compared to other Pennsylvania NGDCs, including UGI Gas affiliates.

Choice suppliers with winter gas at summer prices as it does in storing gas for sales customers? Is the payment lag between the time when UGI Gas incurs the costs for gas supplies to the time it receives payment for the customer comparable for sales and Choice customers?

Neither Mr. Lahoff nor Mr. Herbert presents any such equivalence analysis, either for storage gas or CWC, although the Company appears to acknowledge that it does not incur CWC costs for Choice customers whose NGSs do not participate in the purchase of receivables program. Moreover, despite concluding that the Company incurs CWC costs for both sales and Choice customers, Mr. Herbert continues to allocate CWC solely on the basis of sales volumes.

In the absence of any equivalence analysis from the Company, this issue remains unresolved at this time. As such, I conclude that the 50/50 "split the difference" approach in my direct testimony for inventory costs is not unreasonable, and that my adjusted allocation factor for CWC costs is more consistent with the Company's position than is the sales volume allocator used by Mr. Herbert.

Q. At page 18 of her rebuttal testimony, Ms. Borelli argues that there is no need to perform a statistical analysis to determine the design day demand levels for LFD and XD customers, because these customers must establish daily firm requirement ("DFR"). Do you agree?

A. In general, I do not object to the use of contract demands as a proxy for design day demands, as long as those contract demands represent a reasonable expectation of what the peak day demands for the customers will be. Based on my statistical analysis, the DFRs for the Rate XD class did indeed appear to reasonably represent customer demands under design conditions, and I therefore accepted those values. However, my analysis indicated that the DFRs used by the Company for the LFD class fell well short of what one would reasonably expect from those customers under design conditions. This may occur because the Company has insufficient penalties for demand over-runs, or it may allow for over-runs on an authorized basis, leading customers to "low-ball" their contract demand levels. Or, it is possible that those customers are simply likely to increase their contract demand levels between now and the forecast future test year, to be more consistent with their actual needs. Or it is possible that the Company has not properly reflected customer migration in its analysis, which has been a pervasive problem in this proceeding. In any event, I conclude that, based on the historical usage of the historical LFD customers, the values used by the Company for class-wide LFD peak demand are not representative of the peak demands that they would likely be called upon to serve under design conditions.

Q. At page 19 Ms. Borelli claims that you recommend reducing UGI Gas' design peak day quantity. Is that correct?

A. No. The recommendations in my testimony relate to developing peak day demand allocation factors. The key objective in that exercise is to fairly and reasonably assess each rate class' *relative* contribution to peak day demand. I am *not* proposing to modify the UGI Gas design day demand forecast estimates used to develop upstream supply requirements for sales and Choice customers, or to design the distribution system to meet overall maximum day demand. The only objective of my proposal is to develop a reasonable allocation of demand-related costs in the forecast future test year.

The point I made in my direct testimony was that the Company's "top-down" method implicitly assigned a much higher *relative* level of peak demand to smaller customers than was justified by the load patterns. Much of this distortion was caused by the Company's mismatch between its use of historical peak demands and its forecast consumption levels. Specifically, the Company assumes that there will be significant reductions in Rate R/RT and N/NT customer loads between the historical and future time periods, but continues to rely on system-wide design day demands from the historical period. This is simply poor cost allocation practice, particularly when the Company includes aggressive assumptions regarding load reductions between the historical and future time periods.[2]

Ms. Borelli fails to even acknowledge this inconsistency. As such, the Company's methodology for developing reasonable *relative* peak demand levels in the future test year is biased and unusable. While my estimates are admittedly imperfect, they are far superior to the Company's method in that they do not include the obvious bias against smaller customers.

Q. Let's turn to Mr. Watkins' rebuttal testimony. At pages 2 to 6 of his rebuttal testimony, Mr. Watkins reviews the two most recent Commission decisions cited in your testimony regarding the cost allocation method to be used for gas distribution mains. Please comment.

A. Mr. Watkins acknowledges that the Commission adopted the use of an average-and-excess ("A&E") allocation method for mains costs in both of the cases I referenced. However, he concludes that in neither case did the Commission directly compare the A&E method with the 50/50 peak-and-average ("P&A") method that he recommends in this proceeding and which has been approved by the Commission in the more distant past. He therefore concludes that there is no Commission precedent that favors the A&E approach offered in this proceeding over his recommended method.

In response, I will observe only that it is hard to understand how two specific Commission decisions adopting the use of an A&E allocation factor fail to provide some precedent for the use of the A&E method in this proceeding. However, if by adopting the A&E method in those two cases the Commission was actually retaining its approval of a 50/50 P&A method, I am certain the Commission will inform the parties in this proceeding.

---

[2] In my analysis, I derived design day load factors for each rate class based on the historical analysis, and then applied those load factors to forecast future loads to derive forecast design day demands. In that way, my analysis reasonably reflected the effect of the Company's forecast volume reductions. Had the Company not included such a large reduction in R/RT and N/NT loads, my method would have produced considerably higher design day demands for those classes. Thus, much of Ms. Borelli's complaint about my design day demands being too low arises from the Company's very aggressive assumptions about loss of load between now and 2017.

Q. At page 4, Mr. Watkins makes reference to his own testimony in one of the referenced cases, namely the PPL Gas (now Central Penn Gas) case at Docket No. R-00061398. He indicates that he did not oppose the use of the A&E method in that case because its results ". . . were not materially different than the results that would be obtained under the P&A method." Do you agree?

A. At this writing, I do not believe this is correct. Exhibit IEc-S1 Schedule 3 shows the development of Allocation Factor 5 (distribution mains) in that proceeding, using values from Mr. Watkins' direct testimony cost allocation study (which match the values used by the PPL Gas). As shown in that exhibit, the utility had developed an A&E allocation factor using a 40% average demand weighting factor. This method produced an allocation factor that was very similar to the peak demand allocation factor, and not particularly similar to the average demand allocation factor. For example, the A&E allocator for the Residential class was 35.03 percent, compared to a peak demand allocation factor of 35.12 percent and an average demand allocation factor of 31.09 percent. When derived precisely, the Company's allocation factor represented an allocator that was 1.1 percent based on average demand and 98.9 percent based on peak demand. Mr. Watkins adopted the A&E allocator in that proceeding, and the Commission approved it.

Thus, if anything, Mr. Watkins acceptance of the Company's method and the Commission's approval thereof in that proceeding would support the use of an allocator in the current proceeding that is more heavily weighted toward peak demand rather than less, as Mr. Watkins proposes.

Q. At page 6, Mr. Watkins indicates that he did not participate in the PGW case you reference, but did participate in the subsequent case, and concluded that the Company's A&E approach in that case did not produce results that were materially different from a 50/50P&A approach. Do you agree?

A. No. As shown in the workpapers attached as Exhibit IEc-S1 Schedule 3, PGW's 50/50 A&E allocator in the 2010 rate case implied a weighting of 32 percent average demand and 68 percent peak demand.

Thus, it would certainly appear that Commission precedent in both cited cases does not support a traditional 50/50 P&A allocation method.

4. Revenue Allocation

Q. At page 38, Mr. Lahoff dismisses your revenue allocation proposal on the grounds that you ". . . failed to investigate any specific interruptible customer transactions." Is this correct?

A. No. As I explained earlier, both OCA and OSBA requested detail from the Company supporting interruptible transactions, and the Company declined to provide them. Moreover, Mr. Lahoff's reference to actual interruptible transactions is somewhat curious. The Company itself does not propose to rely on specific interruptible customer transactions for revenue allocation in this proceeding. It proposes to rely on a hybrid allocated cost method, for both determining the magnitude of current rate interruptible revenues and for revenue allocation. In effect, Mr. Lahoff subjects my testimony to a standard that the Company did not apply to itself.

Moreover, as detailed in my rebuttal testimony, I acknowledge that the Company vastly understated current rates interruptible service revenue, and that if a reasonable value is used as a starting point, I do not propose any further increase to those customers.

Q. Mr. Lahoff also concludes that the changes to Mr. Herbert's cost allocation analysis do not justify any changes to the proposed revenue allocation. Please comment.

A. As detailed in the previous section, I conclude that my cost allocation analysis, as updated in my rebuttal testimony, is superior to the Company's approach. As such, I conclude that my revenue allocation proposal in my rebuttal testimony, which is consistent with that study, is the preferred alternative.

5. Rate Design

Q. At page 44 of his rebuttal testimony, Mr. Lahoff argues that, in proposing a reduced customer charge for Rate N/NT, you ". . . improperly apply the principle of gradualism to individual components of rates, rather than to rates as a whole." Is that accurate?

A. No. Customers who take service in Rate N/NT come in a very wide variety of sizes. While I did not undertake a detailed assessment of the range of customer sizes in Rate N/NT in this proceeding, my experience with a variety of NGDCs in Pennsylvania is that there are typically a significant number of relatively small customers in the small general service classes, with loads ranging from 1 to 2 times that of the typical residential customer. For those customers, the Company's proposal would result in a distribution bill increase of 72.0 percent to 38.7 percent, compared to a class average increase of 22.7 percent. Thus, under Mr. Lahoff's standard, the relatively small customers will incur distribution bill increases far in excess of the increases faced by other customers in the class. In contrast, under the proposal in my direct testimony, distribution bill increases for smaller customers in that size range would be 32.0 percent to 15.3 percent, much closer to the class average increases, but directionally consistent with moving the customer charge in line with customer costs.

Q. At page 46 to 47 of his rebuttal, Mr. Lahoff acknowledges that changes in revenue allocation and rate design may cause customers to migrate among rate classes in a manner different from that in the Company's filing, and that the Company reserves its right to update the migration analysis when revenue allocation and rate design is finalized. Is that reasonable?

A. Yes. However, I am advised by counsel that the OSBA similarly reserves its legal right to subject any such update to discovery, analysis and litigation if necessary to ensure that the update is reasonable.

Q. Regarding the Company's proposed TED Rider, Mr. Stoyko testifies at pages 14 to 15 that the proposal is not unduly discriminatory, in that it applies to both new and existing customers. Is that accurate?

A. No. As proposed, the TED Rider makes available below-tariff rates for new loads, either those related to a new customer or an additional load from an existing customer. An existing customer's current load is not eligible for the discount. So, for example, suppose a Home Depot is taking service from the Company at regular tariff rates under Rate DS, which rates are based on normal embedded cost allocation techniques. A new Lowes store opens a few miles away, and asks UGI Gas for discounted rates under Rider TED.

As proposed, the Lowes store would be eligible for the discounted rate, but the Home Depot store would not. It is difficult to understand how the Home Depot store would not see the rates as unduly discriminatory.

Moreover, any effort to try to avoid providing a competitive advantage to the new Lowes customer in this example exposes all other customers to the risk. The basic concept of the TED Rider is that the new customer will be paying rates that are at or above the incremental cost of the new service. If a new customer pays only rates that cover the incremental costs, it will make little contribution to the system and existing ratepayers will see little benefit. As such, in my example, the new Lowes store contributes little to the benefit of all other customers. However, if UGI Gas then offers the same discount to the Home Depot to avoid the obvious discrimination, the revenue lost from that customer will eventually have to be recovered from the rest of the system ratepayers.

It is my understanding that these types of discrimination problems were contributing factors to the gradual elimination of economic development rates for electric utilities in Pennsylvania.

Q. At page 45 of his rebuttal testimony, Mr. Stoyko indicates that the large interruptible rate customers ". . . is already included as a Rate XD customer." Please respond.

A. In its cost allocation and revenue allocation analysis, the Company includes the large interruptible customer in the Interruptible Service rate class. My direct testimony simply indicates that the Company's overall treatment of the Interruptible Service class would benefit from excluding this very large customer from that class for cost allocation and revenue allocation purposes, and that the process would be simpler if this customer were treated like a Rate XD customer. As Mr. Stoyko appears to agree with that sentiment, it is not at all clear why the Company included that customer with the Interruptible Service class in both its initial filing and its rebuttal testimony.

However, I do agree with Mr. Stoyko that rates for this customer should reasonably reflect competitive circumstances, notably the potential for the customer to bypass the UGI Gas system.

5. EE&C Plan

Q. At page 27 of his rebuttal testimony, Mr. Love responds to your proposal to exclude the economic effects of forecast carbon taxes and "DRIPE" in the economic assessment of any EE&C plan adopted by the Company. Has Mr. Love addressed any of your concerns?

A. No. Mr. Love fails to acknowledge or respond to my concern that any benefits to Pennsylvania ratepayers associated with the market price effects of demand reductions are very likely to be more than offset by negative impacts on Pennsylvania gas producers, workers, suppliers and other taxpayers. He also fails to address the fact that no carbon tax is currently in place in Pennsylvania, and that the Commission has explicitly indicated that its policy is to exclude any such costs in the economic analysis of electric industry EE&C programs unless and until a tax is adopted.

Q. Can you respond to Mr. Love's reference to the decision of the Administrative Law Judge in PGW's recent EE&C plan proceeding approving the inclusion of "benefits" associated with the avoidance of still-hypothetical carbon taxes and impacts of price suppression on economic activity and tax revenues from Pennsylvania's gas producing industry?

A. As I indicated in footnote 30 at page 42 of my direct testimony, I am advised by counsel that OSBA will address this issue in its briefs in this matter. Based on my own experience, I can confirm that the Commission has often adopted rules for PGW that are very different from those that apply to investor owned utilities in Pennsylvania.

Q. At pages 27 to 28, Mr. Love argues that the O&M and A&G costs associated with the EE&C programs are causally related to all eligible ratepayers, and not only program beneficiaries. Is this accurate?

A. Of course not. Non-participating customers receive no benefit from the programs, and they therefore have no causal responsibility for the costs. If there were no program beneficiaries, the O&M and A&G costs would not be incurred. These programs exist only to provide benefits to plan participants, and thus all costs associated with the programs are incurred on behalf of those customers.

Although Mr. Love does not so state, it is possible that the Company is claiming that these O&M and A&G costs are startup costs that will benefit all customers over the long term, presumably beyond the end of the current plan. This is also a dubious concept, as it would likely take many decades before every customer benefits from the plan. However, if that is the Company's position, these costs should properly be capitalized and amortized over the appropriate time period. As the Company has not done so, the Company believes that these costs are related only to current program participants.

Q. Mr. Love argues that it is necessary to subsidize the New Construction ("NC") and Non-Residential Retrofit ("NR") programs by more than 50 percent of costs in order to adopt a "holistic" approach to energy conservation and to be in line with the subsidies of programs in other jurisdictions. Do you agree?

A. Mr. Love and I appear to have a philosophical disagreement in this respect. Mr. Love appears to believe that the overall economic gains of these programs justify almost any magnitude of subsidies from non-benefitting ratepayers. For example, as shown in my direct testimony, he proposes that the beneficiaries of the NC program pay for 14% percent of costs, while the non-benefiting ratepayers must pony up the 86% in subsidies.

I, on the other hand, believe that, if utility-sponsored EE&C programs are deemed to be necessary, it is still necessary to maintain a reasonable balance between the desire to achieve the overall economic benefits of energy savings and need to limit the inequities of forcing non-beneficiaries to subsidize the select few benefiting participants. I conclude that Mr. Love's proposal does not represent such a reasonable balance, presumably because that is not his intent.

Thus, to the extent that the Commission wants to maintain a reasonable balance between overall economic efficiency and minimizing inequitable cross-subsidies, I retain my recommendation that subsidies for the NC and NR projects be limited to 50 percent of costs.

Q. At page 29, Mr. Love indicates that portfolio-wide costs are allocated among rate classes in proportion to incentive costs, exclusive of the CHP program. Please comment.

A. Mr. Love clarifies an issue that was not clear to me when I prepared my direct testimony. However, now that the method has been clarified, I must disagree with it. First, I disagree that the CHP program should be exempt from being assigned portfolio-wide costs. The CHP program presumably benefits from the overall costs of administration of the EE&C plan, and it should be assigned its share of the portfolio-wide costs. This is particularly important with the more detailed development of program cost charges adopted by the Company in its rebuttal (with which I agree). Second, overall plan administration costs are likely to be more correlated with program O&M and A&G costs than with incentives costs. As such, I recommend that the Company modify its allocation method to distribute portfolio-wide costs among the various rate categories in proportion to overall utility plan costs, including incentives, O&M and A&G.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Exhibit IEc-S1 Schedule 1
Comparison of Gas Wellhead and NY Harbor Fuel Oil Prices

Date	Henry Hub Natural Gas Spot Price	Date	New York Harbor No. 2 Heating Oil Spot Price FOB		New York Harbor No. 2 Heating Oil Spot Price FOB	
	$/mmbtu		$/gallon	$/mmbtu	Month	12-Month Avg.
Oct-04	6.35	Oct-04	1.485	10.83	4.48	1.85
Nov-04	6.17	Nov-04	1.384	10.09	3.92	2.05
Dec-04	6.58	Dec-04	1.275	9.30	2.72	2.24
Jan-05	6.15	Jan-05	1.316	9.60	3.45	2.44
Feb-05	6.14	Feb-05	1.343	9.79	3.65	2.64
Mar-05	6.96	Mar-05	1.556	11.35	4.39	2.90
Apr-05	7.16	Apr-05	1.523	11.11	3.95	3.15
May-05	6.47	May-05	1.413	10.30	3.83	3.37
Jun-05	7.18	Jun-05	1.612	11.75	4.57	3.67
Jul-05	7.63	Jul-05	1.640	11.96	4.33	3.87
Aug-05	9.53	Aug-05	1.804	13.15	3.62	3.91
Sep-05	11.75	Sep-05	1.963	14.31	2.56	3.79
Oct-05	13.42	Oct-05	1.891	13.79	0.37	3.45
Nov-05	10.30	Nov-05	1.689	12.32	2.02	3.29
Dec-05	13.05	Dec-05	1.707	12.45	-0.60	3.01
Jan-06	8.69	Jan-06	1.751	12.77	4.08	3.06
Feb-06	7.54	Feb-06	1.639	11.95	4.41	3.13
Mar-06	6.89	Mar-06	1.777	12.96	6.07	3.27
Apr-06	7.16	Apr-06	1.978	14.42	7.26	3.54
May-06	6.25	May-06	1.972	14.38	8.13	3.90
Jun-06	6.21	Jun-06	1.925	14.04	7.83	4.17
Jul-06	6.17	Jul-06	1.935	14.11	7.94	4.47
Aug-06	7.14	Aug-06	1.984	14.47	7.33	4.78
Sep-06	4.90	Sep-06	1.699	12.39	7.49	5.19
Oct-06	5.85	Oct-06	1.648	12.02	6.17	5.68
Nov-06	7.41	Nov-06	1.648	12.02	4.61	5.89
Dec-06	6.73	Dec-06	1.684	12.28	5.55	6.40
Jan-07	6.55	Jan-07	1.528	11.14	4.59	6.45
Feb-07	8.00	Feb-07	1.693	12.34	4.34	6.44
Mar-07	7.11	Mar-07	1.742	12.70	5.59	6.40
Apr-07	7.60	Apr-07	1.864	13.59	5.99	6.30
May-07	7.64	May-07	1.884	13.74	6.10	6.13
Jun-07	7.35	Jun-07	1.991	14.52	7.17	6.07
Jul-07	6.22	Jul-07	2.072	15.11	8.89	6.15
Aug-07	6.22	Aug-07	1.984	14.47	8.25	6.23
Sep-07	6.08	Sep-07	2.179	15.89	9.81	6.42
Oct-07	6.74	Oct-07	2.282	16.64	9.90	6.73
Nov-07	7.10	Nov-07	2.586	18.86	11.76	7.33
Dec-07	7.11	Dec-07	2.574	18.77	11.66	7.84
Jan-08	7.99	Jan-08	2.558	18.65	10.66	8.34
Feb-08	8.54	Feb-08	2.644	19.28	10.74	8.88
Mar-08	9.41	Mar-08	3.066	22.36	12.95	9.49
Apr-08	10.18	Apr-08	3.226	23.52	13.34	10.10
May-08	11.27	May-08	3.615	26.36	15.09	10.85
Jun-08	12.69	Jun-08	3.801	27.72	15.03	11.51
Jul-08	11.09	Jul-08	3.759	27.41	16.32	12.12
Aug-08	8.26	Aug-08	3.169	23.11	14.85	12.67
Sep-08	7.67	Sep-08	2.911	21.23	13.56	12.99
Oct-08	6.74	Oct-08	2.239	16.33	9.59	12.96
Nov-08	6.68	Nov-08	1.843	13.44	6.76	12.54
Dec-08	5.82	Dec-08	1.402	10.22	4.40	11.94
Jan-09	5.24	Jan-09	1.465	10.68	5.44	11.50
Feb-09	4.52	Feb-09	1.279	9.33	4.81	11.01

Exhibit IEc-S1 Schedule 1
Comparison of Gas Wellhead and NY Harbor Fuel Oil Prices

Date	Henry Hub Natural Gas Spot Price	Date	New York Harbor No. 2 Heating Oil Spot Price FOB		New York Harbor No. 2 Heating Oil Spot Price FOB	
	$/mmbtu		$/gallon	$/mmbtu	Month	12-Month Avg.
Mar-09	3.96	Mar-09	1.277	9.31	5.35	10.38
Apr-09	3.50	Apr-09	1.357	9.89	6.39	9.80
May-09	3.83	May-09	1.473	10.74	6.91	9.12
Jun-09	3.80	Jun-09	1.747	12.74	8.94	8.61
Jul-09	3.38	Jul-09	1.628	11.87	8.49	7.96
Aug-09	3.14	Aug-09	1.865	13.60	10.46	7.59
Sep-09	2.99	Sep-09	1.728	12.60	9.61	7.26
Oct-09	4.01	Oct-09	1.929	14.07	10.06	7.30
Nov-09	3.66	Nov-09	1.981	14.44	10.78	7.64
Dec-09	5.35	Dec-09	1.968	14.35	9.00	8.02
Jan-10	5.83	Jan-10	2.046	14.92	9.09	8.32
Feb-10	5.32	Feb-10	1.978	14.42	9.10	8.68
Mar-10	4.29	Mar-10	2.083	15.19	10.90	9.14
Apr-10	4.03	Apr-10	2.204	16.07	12.04	9.62
May-10	4.14	May-10	2.040	14.88	10.74	9.93
Jun-10	4.80	Jun-10	2.032	14.82	10.02	10.02
Jul-10	4.63	Jul-10	1.979	14.43	9.80	10.13
Aug-10	4.32	Aug-10	2.016	14.70	10.38	10.13
Sep-10	3.89	Sep-10	2.090	15.24	11.35	10.27
Oct-10	3.43	Oct-10	2.242	16.35	12.92	10.51
Nov-10	3.71	Nov-10	2.320	16.92	13.21	10.71
Dec-10	4.25	Dec-10	2.468	18.00	13.75	11.11
Jan-11	4.49	Jan-11	2.604	18.99	14.50	11.56
Feb-11	4.09	Feb-11	2.770	20.20	16.11	12.14
Mar-11	3.97	Mar-11	3.034	22.12	18.15	12.75
Apr-11	4.24	Apr-11	3.196	23.30	19.06	13.33
May-11	4.31	May-11	2.952	21.53	17.22	13.87
Jun-11	4.54	Jun-11	2.967	21.63	17.09	14.46
Jul-11	4.42	Jul-11	3.068	22.37	17.95	15.14
Aug-11	4.06	Aug-11	2.946	21.48	17.42	15.73
Sep-11	3.90	Sep-11	2.921	21.30	17.40	16.23
Oct-11	3.57	Oct-11	2.953	21.53	17.96	16.65
Nov-11	3.24	Nov-11	3.054	22.27	19.03	17.14
Dec-11	3.17	Dec-11	2.891	21.08	17.91	17.48
Jan-12	2.67	Jan-12	3.054	22.27	19.60	17.91
Feb-12	2.51	Feb-12	3.196	23.30	20.79	18.30
Mar-12	2.17	Mar-12	3.217	23.46	21.29	18.56
Apr-12	1.95	Apr-12	3.150	22.97	21.02	18.72
May-12	2.43	May-12	2.913	21.24	18.81	18.86
Jun-12	2.46	Jun-12	2.619	19.10	16.64	18.82
Jul-12	2.95	Jul-12	2.813	20.51	17.56	18.79
Aug-12	2.84	Aug-12	3.045	22.20	19.36	18.95
Sep-12	2.85	Sep-12	3.134	22.85	20.00	19.16
Oct-12	3.32	Oct-12	3.140	22.90	19.58	19.30
Nov-12	3.54	Nov-12	3.009	21.94	18.40	19.25
Dec-12	3.34	Dec-12	2.995	21.84	18.50	19.30
Jan-13	3.33	Jan-13	3.068	22.37	19.04	19.25
Feb-13	3.33	Feb-13	3.168	23.10	19.77	19.16
Mar-13	3.81	Mar-13	2.943	21.46	17.65	18.86
Apr-13	4.17	Apr-13	2.742	19.99	15.82	18.43
May-13	4.04	May-13	2.739	19.97	15.93	18.19
Jun-13	3.83	Jun-13	2.752	20.07	16.24	18.15
Jul-13	3.62	Jul-13	2.885	21.04	17.42	18.14

Exhibit IEc-S1 Schedule 1
Comparison of Gas Wellhead and NY Harbor Fuel Oil Prices

Date	Henry Hub Natural Gas Spot Price	Date	New York Harbor No. 2 Heating Oil Spot Price FOB		New York Harbor No. 2 Heating Oil Spot Price FOB	
	$/mmbtu		$/gallon	$/mmbtu	Month	12-Month Avg.
Aug-13	3.43	Aug-13	2.958	21.57	18.14	18.04
Sep-13	3.62	Sep-13	2.961	21.59	17.97	17.87
Oct-13	3.68	Oct-13	2.940	21.44	17.76	17.72
Nov-13	3.64	Nov-13	2.923	21.31	17.67	17.66
Dec-13	4.24	Dec-13	3.032	22.11	17.87	17.61
Jan-14	4.71	Jan-14	3.063	22.33	17.62	17.49
Feb-14	6.00	Feb-14	3.061	22.32	16.32	17.20
Mar-14	4.90	Mar-14	2.912	21.23	16.33	17.09
Apr-14	4.66	Apr-14	2.888	21.06	16.40	17.14
May-14	4.58	May-14	2.860	20.85	16.27	17.17
Jun-14	4.59	Jun-14	2.882	21.01	16.42	17.18
Jul-14	4.05	Jul-14	2.776	20.24	16.19	17.08
Aug-14	3.91	Aug-14	2.753	20.07	16.16	16.92
Sep-14	3.92	Sep-14	2.633	19.20	15.28	16.69
Oct-14	3.78	Oct-14	2.424	17.68	13.90	16.37
Nov-14	4.12	Nov-14	2.249	16.40	12.28	15.92
Dec-14	3.48	Dec-14	1.856	13.53	10.05	15.27
Jan-15	2.99	Jan-15	1.616	11.78	8.79	14.53
Feb-15	2.87	Feb-15	1.873	13.66	10.79	14.07
Mar-15	2.83	Mar-15	1.632	11.90	9.07	13.47
Apr-15	2.61	Apr-15	1.722	12.56	9.95	12.93
May-15	2.85	May-15	1.832	13.36	10.51	12.45
Jun-15	2.78	Jun-15	1.762	12.85	10.07	11.92
Jul-15	2.84	Jul-15	1.557	11.35	8.51	11.28
Aug-15	2.77	Aug-15	1.387	10.11	7.34	10.54
Sep-15	2.66	Sep-15	1.423	10.38	7.72	9.91
Oct-15	2.34	Oct-15	1.404	10.24	7.90	9.41
Nov-15	2.09	Nov-15	1.316	9.60	7.51	9.02
Dec-15	1.93	Dec-15	1.037	7.56	5.63	8.65
Jan-16	2.28	Jan-16	0.939	6.85	4.57	8.30
Feb-16	1.99	Feb-16	0.972	7.09	5.10	7.82
Mar-16	1.73	Mar-16	1.132	8.25	6.52	7.61
Apr-16	1.92	Apr-16	1.188	8.66	6.74	7.34
May-16	1.81	May-16	1.488	10.85	9.04	7.22
Jun-16	2.09	Jun-16	1.492	10.88	8.79	7.11
Jul-16	2.24	Jul-16	1.495	10.90	8.66	7.13
Aug-16	2.32	Aug-16	1.497	10.92	8.59	7.23
Sep-16	2.36	Sep-16	1.507	10.98	8.62	7.31
Oct-16	2.44	Oct-16	1.509	11.00	8.57	7.36
Nov-16	2.64	Nov-16	1.581	11.53	8.89	7.48
Dec-16	2.93	Dec-16	1.531	11.16	8.23	7.69
Jan-17	3.06	Jan-17	1.536	11.20	8.14	7.99
Feb-17	3.05	Feb-17	1.547	11.28	8.23	8.25
Mar-17	3.01	Mar-17	1.542	11.25	8.24	8.40
Apr-17	2.79	Apr-17	1.524	11.11	8.32	8.53
May-17	2.78	May-17	1.528	11.14	8.36	8.47
Jun-17	2.82	Jun-17	1.541	11.24	8.42	8.44
Jul-17	2.86	Jul-17	1.561	11.38	8.53	8.43
Aug-17	2.86	Aug-17	1.570	11.45	8.58	8.43
Sep-17	2.84	Sep-17	1.576	11.49	8.65	8.43

Sources:
DOE/EIA Henry Hub and NY Harbor #2 Fuel Oil Monthly Spot Prices (to April 2016)

Exhibit IEc-S1 Schedule 1

Comparison of Gas Wellhead and NY Harbor Fuel Oil Prices

Date	Henry Hub Natural Gas Spot Price	Date	New York Harbor No. 2 Heating Oil Spot Price FOB		New York Harbor No. 2 Heating Oil Spot Price FOB	
	$/mmbtu		$/gallon	$/mmbtu	Month	12-Month Avg.
Futures prices, Barchart.com May 23, 2016 (Open Values (May 16 to Sept 17)						
mmbtu/bbl	5.76	(EIA, 2013 value)				

Comparison to UGI Revenues

	Oil Price Premium $/mmbtu	Revenue $mm	Mcfs	Revenue	$/Mcf
FY05	3.79	19.64	26,988,273	19,643,398	0.728
FY06	5.19	21.29	26,115,100	21,285,353	0.815
FY07	6.42	25.98	29,941,549	25,981,114	0.868
FY08	12.99	26.62	34,279,651	26,616,984	0.776
FY09	7.26	25.69	29,497,246	25,694,292	0.871
FY10	10.27	25.19	38,897,370	25,185,071	0.647
FY11	16.23	24.48	46,939,070	24,483,481	0.522
FY12	19.16	22.30	61,928,488	22,297,743	0.360
FY13	17.87	21.98	56,254,762	21,983,621	0.391
FY14	16.69	22.41	50,522,402	22,408,953	0.444
FY15	9.91	20.38	53,754,975	20,379,900	0.379
FY16*	7.31	12.64	52,015,690	12,639,950	0.243
FY17	8.43	4.90	50,276,404	4,900,000	0.097

* Linear interpolation

Source: OCA-XIII-1, Exhibit E

Exhibit IEc-S1 Schedule 2

UGI Proposed Allocation of Small and Large Mains

Source: Exhibit D

	Total	R	N	DS	LFD	XD	Interruptible
Actual							
Small Mains	215,322,849	114,379,497	70,798,153	12,467,193	5,835,249	**0**	11,842,757
Large Mains	328,559,063	155,835,564	96,399,229	16,526,521	36,470,056	**0**	23,327,693
Direct	14,193,075					13,686,419	506,656
Adjusted						6.70%	0.00%
Small Mains	216,239,839	114,379,497	70,798,153	12,467,193	5,835,249	916,990	11,842,757
Large Mains	341,835,148	155,835,564	96,399,229	16,526,521	36,470,056	12,769,429	23,834,349
Total	**558,074,987**	**270,215,061**	**167,197,382**	**28,993,714**	**42,305,305**	**13,686,419**	**35,677,106**
Small Mains %	**38.7%**	**42.3%**	**42.3%**	**43.0%**	**13.8%**	**6.7%**	**33.2%**
Avg Day Throughput	335,300	62,313	38,743	8,875	39,903	**47,722**	137,744
Customers	387,919	348,120	38,394	592	464	27	322
Ann T'put per Customer	315	65	368	5,472	31,389	645,131	156,138
Index (R=1)	4.8	1.0	5.6	83.8	480.4	9,874.3	2,389.8

Exhibit IEc-S1 Schedule 3

Implied Average Demand Component of OCA Mains Allocation Factor in PPL Gas 2006 proceeding

Factor 5: Mains	% Average Wt.	Total	Residential	GSS	GSL	LVS	Storage
Peak		167,652	58,879	39,876	26,054	42,843	-
Average		65,939	17,842	11,393	8,142	28,562	-
Excess		101,713	41,037	28,483	17,912	14,281	0
Peak		100.00%	35.12%	23.78%	15.54%	25.55%	
Average		100.00%	27.06%	17.28%	12.35%	43.32%	
Excess		100.00%	40.35%	28.00%	17.61%	14.04%	
A&E	40.0%	100.00%	35.03%	23.71%	15.51%	25.75%	
Equivalent P&A	1.1%	100.00%	35.03%	23.71%	15.51%	25.75%	
Traditonal P&A	50.0%	100.00%	31.09%	20.53%	13.94%	34.44%	

Source: OCA Statement No. 3, Docket No. R-00061398, Schedule GAW-1, pages 21 and 22 of 38.

Implied Average Demand Component of PGW Mains Allocation Factor

	% Average Wt.	350 Total	R-NH	R-H	C-NH	C-H	I-NH	I-H	M-NH	M-H	PHA	INT	GTS/IT
Design Day Mains		736,265	5,775	523,381	13,089	110,855	2,418	9,042	4,562	15,594	10,163	2,817	38,569
Throughput		70,197,299	718,203	40,567,863	1,689,000	9,144,308	275,869	749,160	280,158	1,064,447	832,221	798,433	14,077,637
Average Day		192,321	1,968	111,145	4,627	25,053	756	2,052	768	2,916	2,280	2,187	38,569
Excess Day		543,944	3,807	412,236	8,462	85,802	1,662	6,990	3,794	12,678	7,883	630	0
Peak		100.00%	0.78%	71.09%	1.78%	15.06%	0.33%	1.23%	0.62%	2.12%	1.38%	0.38%	5.24%
Average		100.00%	1.02%	57.79%	2.41%	13.03%	0.39%	1.07%	0.40%	1.52%	1.19%	1.14%	20.05%
Excess		100.00%	0.70%	75.79%	1.56%	15.77%	0.31%	1.28%	0.70%	2.33%	1.45%	0.12%	0.00%
PGW A&E Method	50.0%	100.00%	0.86%	66.79%	1.98%	14.40%	0.35%	1.18%	0.55%	1.92%	1.32%	0.63%	10.03%
Equivalent P&A	32.3%	100.00%	0.86%	66.79%	1.98%	14.40%	0.35%	1.18%	0.55%	1.92%	1.32%	0.63%	10.03%
Traditonal P&A	50.0%	100.00%	0.90%	64.44%	2.09%	14.04%	0.36%	1.15%	0.51%	1.82%	1.28%	0.76%	12.65%

Source: OCA Statement No. 4, Docket No. R-2009-2139884, Schedule GAW-1, page 10 of 13.